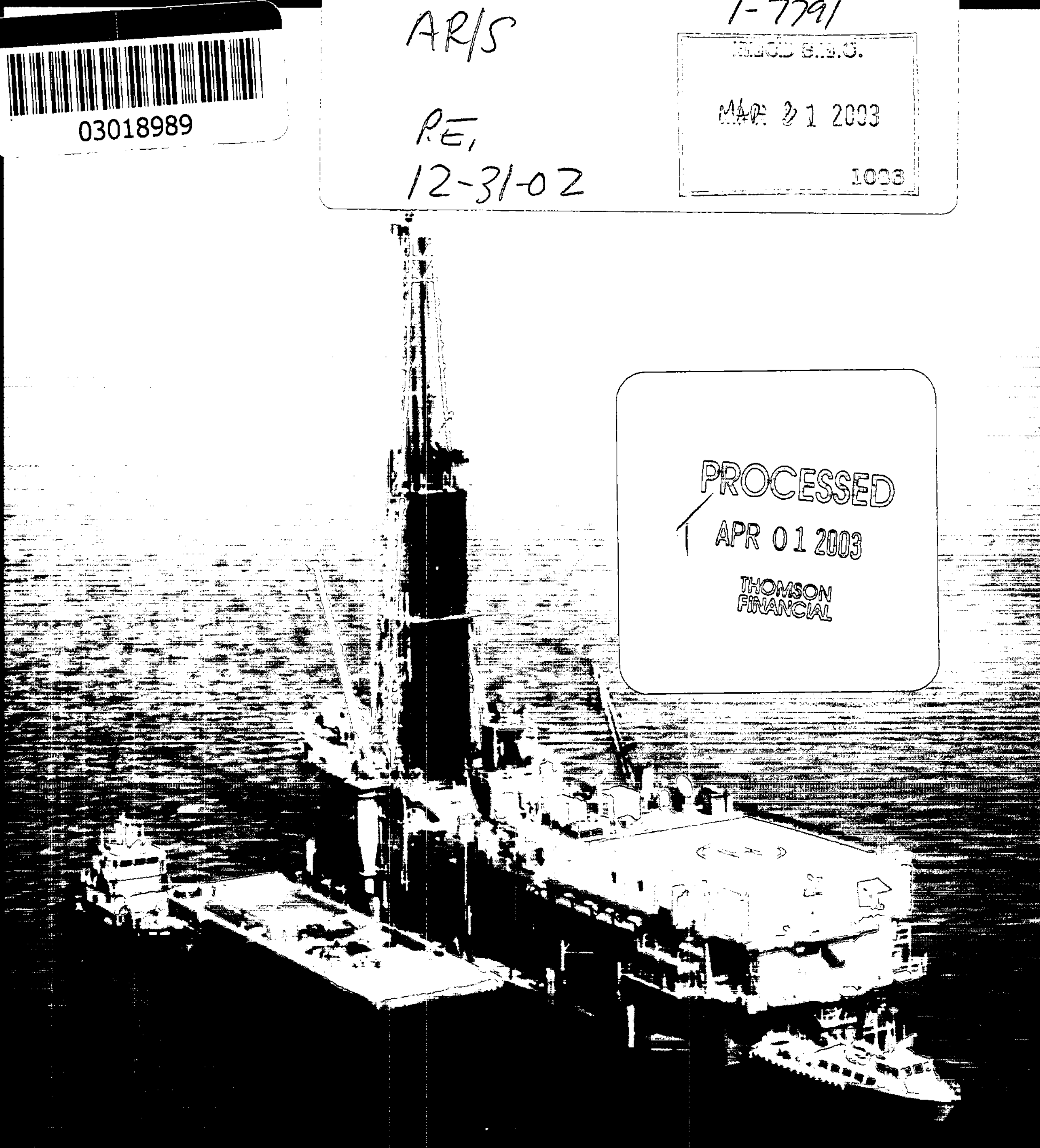
McMoRan Exploration Co.
2002 Annual Report and Form 10-K



On the cover: Drilling rig No. 52 owned by THE Offshore Drilling Company, a division of Transocean Inc., is shown on location at McMoRan's 2002 "JB Mountain" discovery at South Marsh Island Block 223 in shallow water offshore Vermilion Parish, Louisiana. The JB Mountain exploratory well was drilled to a measured depth of 22,000 feet, and was evaluated with wireline logs, formation tests, and flow-tests, which indicated that significant intervals of hydrocarbon pay were encountered. McMoRan expects the well to commence production in the second quarter of 2003 and believes the well has a potential of producing over 60 million cubic feet of gas per day and 4,900 barrels of condensate. A second JB Mountain well is planned for drilling in 2003. The JB Mountain prospect is located in an area where McMoRan is participating in an exploration program that controls approximately 80,000 acres.

McMoRan Exploration Co.

TO OUR SHAREHOLDERS:

The year 2002 was one of solid achievement for McMoRan. Our oil and gas exploration prospects in the Gulf of Mexico, together with a broad scope of new business opportunities, position us to build significant value for our shareholders.

We have an inventory of oil and gas exploration prospects with substantial reserve potential available for drilling. Today's market conditions for natural gas have become increasingly attractive. With strong demand for natural gas in North America and natural gas storage at record lows, McMoRan is "prospect rich" at a time when the industry is starved for quality prospects. Because our drilling prospects are located near existing infrastructure, production from discoveries can be established quickly. Our recent important discovery at JB Mountain in South Marsh Island Block 223, a prospect we generated, evidences the existence of high potential productive sands in deep structures in shallow water beneath structures where significant hydrocarbons have previously been produced.

Our K-Mc Energy Ventures ("K-Mc") alliance with K1 Ventures Limited ("K1") enables us to participate in the future acquisition of energy-related businesses and to pursue highly attractive alternative uses for our Main Pass infrastructure used previously in our discontinued sulphur mining operations. The alliance combines the financial resources and expertise of K1, a publicly owned investment company listed on the Singapore Securities Exchange, with our experience in the energy sector, which will enable us to identify high-quality opportunities at attractive values. K-Mc's recent acquisition of our Main Pass oil reserves and production facilities marks the first acquisition by this alliance.

These opportunities follow the successful execution of our financial plan established in early 2002 to address the liquidity issues resulting from the discontinuation of our sulphur operations and the funding of our oil and gas exploration activities. During 2002, we accomplished the following:

- Sold three oil and gas properties for $60 million while retaining a potentially valuable reversionary interest in the properties and potentially significant exploration rights.
- Raised $33.7 million with a convertible preferred stock offering.
- Sold substantially all of our remaining sulphur assets for $58 million.
- Entered into a fixed-price contract to address our Main Pass and Caminada sulphur mine reclamation obligations.
- Entered into an exploration agreement in which a third party has funded or will fund all of our exploration and development costs on four prospects, while we retained a potentially significant reversionary interest.
- Formed the K-Mc Energy Ventures alliance.

These transactions – fully described in our Annual Report on Form 10-K which follows this letter – eliminated our bank debt and provided positive working capital and unrestricted cash of $14.3 million at December 31, 2002.

We expect the JB Mountain well will commence production during the second quarter of 2003. The well, which was drilled to a measured depth of approximately 22,000 feet, was evaluated with wireline logs and formation tests, which indicate significant intervals of hydrocarbon pay. Based on a flow test, we believe the well has a potential of producing over 60 million cubic feet of gas and 4,900 barrels of condensate per day. Plans for a second JB Mountain well are being developed.

JB Mountain is part of an exploration program involving approximately 80,000 acres on portions of OCS Lease 310 and portions of the adjoining Louisiana State Lease 340 in the shallow waters of the Gulf of Mexico. Under terms of the program, our partner is funding all costs attributable to McMoRan's interests in four prospects and will own the entire program interest until the program's aggregate production totals 100 billion cubic feet of gas equivalent, at which point 50 percent of the interest would revert to us.

Our success at JB Mountain enhances the value of our exploration rights covering over 375,000 gross acres in the Gulf of Mexico because it substantiates the geologic concepts underlying our shallow-water, deep-gas strategy. Our intensive exploration analysis has identified over 20 drilling prospects, many of which are high-risk, high-potential prospects near existing production infrastructure. We estimate gross unrisked potential* for seven near-term prospects available for drilling during 2003 other than JB Mountain to be over 5.4 trillion cubic feet of natural gas equivalent (Tcfe) with net unrisked potential* to our interest of approximately 1.6 Tcfe. After providing for participation by industry partners in funding capital costs, the remaining incremental value potential for our company is substantial.

Exploratory drilling began in February 2003 on another prospect in the program, the Mound Point Offset prospect in Louisiana State Lease 340. This well has a planned total depth of 18,700 feet and is located approximately one mile from a previous Mound Point exploratory well we drilled during 2001. McMoRan's Mound Point well flowed at various rates from 10 to 20 million cubic feet per day before mechanical problems required it to be shut-in and temporarily abandoned. The program holds a 55 percent working interest and a 38.8 percent net revenue interest in JB Mountain, and a 30.4 percent working interest and 21.6 percent net revenue interest in the Mount Point Offset.

The results at JB Mountain indicate a potentially significant deep hydrocarbon complex in the OCS 310 and SL 340 area that will require several additional wells to delineate. JB Mountain and Mound Point are separate prospects six miles apart, but they are closely related geologically. Each is positioned below large shallow reservoirs developed over the past half-century, which have produced 3.3 Tcfe and 2.5 Tcfe from the Tiger Shoal and Mount Point fields, respectively. The geological features of the JB Mountain and Mound Point Offset prospects represent the deep expressions of structures that created these two shallower fields.

Independent reserve engineers' estimates of McMoRan's proven oil and gas reserves as of December 31, 2002 were 17.5 Billion cubic feet of natural gas equivalent (Bcfe), and reflect property sales of 54.2 Bcfe, production of 12.8 Bcfe, and revisions of 2.2 Bcfe during 2002. Including McMoRan's one-third equity interest in K-Mc I's Main Pass oil reserves, McMoRan's reserves total 29.2 Bcfe. No reserves are included from JB Mountain or for the potential reversionary interest from the three properties sold in early 2002. McMoRan's in-house estimates of proved, probable and possible ("3P") reserves* were 188.1 Bcfe, including 33.3 Bcfe attributable to the estimated reversionary interest on the three properties sold in February 2002, with no reserves attributed to JB Mountain.

Our K-Mc alliance should provide opportunities for McMoRan to participate in the acquisition of energy-related businesses in the window of opportunity resulting from the dramatic changes taking place in the energy industry. Our alliance is evaluating investment opportunities involving the purchase of oil and gas reserves, the power generation and distribution sectors and the storage and handling of crude oil, petroleum products and natural gas, including liquefied natural gas ("LNG") and compressed natural gas ("CNG"). K1 provides financial resources and financing expertise to K-Mc and we provide industry and management expertise, which together create a platform for K-Mc to pursue opportunities which could be financially important to our shareholders.

The initial transaction for the K-Mc alliance involved the acquisition of McMoRan's oil reserves and production facilities at Main Pass. Main Pass 299 is currently producing approximately

3,500 barrels of oil per day. In December, K-Mc Venture I LLC ("K-Mc I") was formed. K-Mc I is owned two-thirds by K1 and one-third by us. K-Mc I acquired our Main Pass oil production facilities and has an option to acquire certain of our remaining Main Pass 299 facilities to be the basis for new business activities using the site's unique infrastructure. The Main Pass facility is suited for a variety of applications, including the use of its massive salt dome for storage of natural gas and other hydrocarbons. Credit support for the transaction was provided by K1. We operate the Main Pass facilities on behalf of K-Mc I under a management agreement.

Since ceasing sulphur production from our Main Pass Mine in 2000, we have been transforming the facilities for potential use as a support hub for deepwater oil and gas production as well as an import facility for natural gas storage. The surface platforms and related structures at Main Pass, together with the two-mile diameter caprock and salt dome beneath it, have significant capacity and potential for a variety of commercial activities. Alternative uses of the facilities include the disposal of non-hazardous oilfield drill cuttings from offshore oil and gas drilling activities. Also, the planned facilities would be the first of its kind to receive, process, and store LNG and CNG, using Main Pass's existing substantial structures and the significant storage capacity in its salt dome.

From a financial standpoint, in 2002 we recorded net income of $17.0 million, $0.91 per share, compared to a loss of $148.1 million, $9.33 per share, in 2001. Our oil and gas operations accounted for $18.6 million of net income reflecting $44.1 million of gains associated with oil and gas property sales and losses of $13.0 million reflecting non-productive exploration drilling, geological and geophysical costs and $7.6 million of impairment charges.

We express our gratitude to our directors, employees and business partners for their continued hard work and dedication. Their efforts have enabled us to position McMoRan for these exciting opportunities to add value for our shareholders, both through oil and gas exploration on our extensive acreage and through our new K-Mc alliance, which provides us potential exposure to a broad array of energy-related businesses.

Sincerely,

James R. Moffett
Co-Chairman of the Board

Richard C. Adkerson
Co-Chairman of the Board
President and Chief Executive Officer

March 21, 2003

**Cautionary Statement: The Securities and Exchange Commission (SEC) permits 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-house estimates of proved, probable and possible ("3P") reserves" to provide an indication of our estimates of the potentially recoverable quantities of oil and gas from our proved properties. We also provide 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.*

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, 2002

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

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 [ ] No [X]

The aggregate market value of the voting stock held by non-affiliates of the registrant was approximately $63,400,000 on March 12, 2003, and was approximately $42,300,000 on June 28, 2002.

On March 12, 2003, there were issued and outstanding 16,345,039 shares of the registrant's Common Stock, par value $0.01 per share, and on June 28, 2002 there were issued and outstanding 15,998,832 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Proxy Statement submitted to the registrant's stockholders in connection with the registrant's 2003 Annual Meeting of Stockholders to be held on May 1, 2003 are incorporated by reference into Part III (Items 10, 11, 12 and 13) of this report.

McMoRan Exploration Co.
Annual Report on Form 10-K for
the Fiscal Year ended December 31, 2002

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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 report 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.

OVERVIEW

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. During 2002 we exited the sulphur business, which previously involved the purchasing, transporting, terminaling, processing and marketing of sulphur.

We have provided definitions for some of industry terms we use in a glossary on page 19.

Combination of McMoRan Oil & Gas and Freeport Sulphur. Our company was created on November 17, 1998 when McMoRan Oil & Gas Co. and Freeport-McMoRan Sulphur Inc. combined their operations. As a result, McMoRan Oil & Gas LLC (MOXY) and Freeport-McMoRan Sulphur LLC (Freeport Sulphur) became our wholly owned subsidiaries. The transaction was treated for accounting purposes as a purchase, with MOXY as the acquiring entity. See Note 1 of the Notes to Consolidated Financial Statements located in Item 8. of this Form 10-K. All subsequent references to Notes refer to the Notes to the Consolidated Financial Statements located in Item 8. of this Form 10-K.

Business Plan Implementation. Our primary objective entering 2002 was to address significant liquidity issues resulting from adverse business conditions affecting our former sulphur operations and significant nonproductive exploratory drilling and related costs incurred during 2000 and 2001. In addition to resolving these issues, our business plan included arranging for third parties, or otherwise to secure financing, to drill high-potential, deep-gas exploratory prospects on our existing leasehold acreage, which primarily includes locations in the shallow-water depths of the Gulf of Mexico in federal and state waters offshore Louisiana and Texas where production could be established relatively quickly and inexpensively because of the shallow water and close proximity to existing oil and gas production infrastructure. Through an evaluation of our leasehold inventory, we have identified over 20 drilling prospects. We have focused on arranging for the drilling and evaluation of these prospects. For more information regarding our business plan and transactions completed during 2002 to accomplish our business plan and meet our remaining financial obligations, see Items 7. and 7A. of this Form 10-K and Notes 2, 3, 4 and 10 and for the related risks, see "Risk Factors."

During 2003, we will continue to pursue exploration activities on our lease acreage in the Gulf of Mexico, principally through drilling arrangements involving funding by third parties. In addition, we will continue to address our reclamation obligations resulting from our discontinued sulphur operations. Funding for a substantial portion of our Main Pass reclamation activities has been secured through the Main Pass joint venture transaction and we are continuing our pursuit of the development of alternative business uses for the remaining Main Pass facilities. We are focused on preserving our financial resources and our liquidity through carefully managing our operations and limiting costs in all areas of our business. Events involving uncertainties, including those beyond our control, could have an adverse impact on our financial resources and liquidity. See "Risk Factors" below.

Oil and Gas Background. We and our predecessors have conducted oil and gas exploration, development and production operations principally in the Gulf of Mexico and the Gulf Coast region for more than 25 years. These operations have provided us with an extensive geological and geophysical data base, as well as significant technical and operational expertise in the Gulf of Mexico and Gulf Coast region. We are focused on these areas because of the following:

- we have developed significant expertise and have an extensive data base including information about the geology and geophysics in this region;
- we believe there are significant reserves in the region that have not yet been discovered; and
- the necessary infrastructure for efficiently developing, producing and transporting oil and gas exists in this region, which allows an operator to reduce costs and the time required to develop, produce and transport oil and gas.

Effective January 2000, we entered into transactions with Texaco Exploration and Production Inc. (Texaco), which subsequently became a subsidiary of ChevronTexaco Corp., and Shell Offshore Inc. (Shell) which significantly enhanced our presence on the continental shelf of the Gulf of Mexico. For additional information about our Texaco and Shell transactions, see "Exploration Activities" included within Items 7. and 7A. of this Form 10-K and Note 5.

In May 2002, we entered into a farm-out agreement with El Paso Production Company (El Paso), a subsidiary of El Paso Corporation, with respect to four of our prospects, which is described below in "Oil and Gas Operations – Exploration Arrangement with El Paso." We intend to pursue additional farm-out or other similar exploration arrangements with other parties to provide funds for the exploration and development of our other prospects.

Sulphur Background. In June 2002, we sold substantially all of the remaining assets that comprised our recovered sulphur transportation, terminaling, logistics and marketing (transportation and terminaling) business to a joint venture owned by unrelated parties. For more information on this sales transaction and our exit from the sulphur business, see "Sulphur Operations" below.

OIL AND GAS OPERATIONS

Oil and Gas Properties. As of December 31, 2002, we owned or controlled interests in 82 oil and gas leases in the Gulf of Mexico and onshore Louisiana and Texas covering approximately 376,000 gross acres (approximately 196,000 acres net to us). This acreage includes approximately 100,000 gross and 26,000 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, 2002 to be approximately 17.5 Bcfe, consisting of 14.0 Bcf of natural gas and 0.6 MMBbls of crude oil and condensate using the definitions required by the SEC (see "Oil and Gas Reserves" below). These amounts do not include any reserves that may be associated with our potential reversionary interests, including the JB Mountain discovery, or the estimated 1.9 MMBbls of crude oil or 11.6 Bcfe of reserves associated with our remaining 33.3 percent interest in the Main Pass oil operations. See "Sulphur Operations - Formation of Joint Venture" below. For additional information regarding our estimated reserves, see Note 12.

Our production during 2002 totaled approximately 5.9 Bcf of natural gas and 1.1 MMBbls of oil and condensate or an aggregate of 12.6 Bcfe. Our production during 2002 included approximately 0.8 Bcf of natural gas and 1.0 MMBbls of oil and condensate or an aggregate of 7.0 Bcfe attributable to oil and gas properties sold during the year, including the oil operations at Main Pass, which were sold to a joint venture in which we retained a 33.3 percent interest.

The table below sets forth approximate information, as of December 31, 2002, with respect to our producing properties and the four exploration prospects included in our exploration arrangement with El Paso. Following the table is a summary of activities on these properties during 2002 and early 2003.

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	42.2 [d]	33.4 [d]	MMR	90	50	-
Eugene Island Blocks 97/108	38.0	27.2	OEI [e]	90	50	5,000
Ship Shoal Block 296[f]	12.4	8.7	APC [g]	260	62	5,000

Field, Lease or Well	Working Interest	Net Revenue Interest	Operator	Water Depth	Location Offshore Louisiana	Gross Acreage	
	(%)	(%)		(in feet)	(miles)		
Exploratory [h]							
Eugene Island Blocks 96/97/108/109	40.0	28.8	OEI	32	50	20,000	
South Marsh Island Block 223	55.0	38.8	EP [i]	10		-	(j)
South Marsh Island Block 207	90.0	38.9	EP	10		-	(j)
Louisiana State Lease 340	30.4	21.6	EP	10		-	(j)

a. Sold in mid-December 2002 to the joint venture in which we retained a 33.3 percent interest. Ownership interests shown reflect our retained interest in the joint venture.
b. Subject to net profits 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. Ocean Energy Inc.
f. We sold 80 percent of property interests effective January 1, 2002. We retained our interest in exploratory prospects lying 100 feet below the stratigraphic equivalent of the deepest currently producing interval. We also retained a potential reversionary interest. 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 all four prospects, net to the program's interests, exceeds 100 Bcfe.
i. El Paso Production Company.
j. Prospects located in area where we control an approximate 80,000-acre exploration position including these leases and portions of OCS Lease 310 and adjoining portions of Louisiana State Lease 340.

Producing Properties

The following is a summary of our properties that were producing at the beginning of 2002.

- **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. Subsequently, one of the wells was shut-in and we are currently performing remedial operations to restore its production. The field currently has two producing wells. Average current gross production totals 3.9 MMcfe/d, 1.4 MMcfe/d net to MOXY.

- **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 1.0 MMcfe/d, 0.4 MMcfe/d net to us.

- **Eugene Island Block 193.** During the fourth quarter of 2000, we initiated drilling the Eugene Island Block 193 (North Tern Deep 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 mid-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 substantially shut-in. We are currently considering remedial alternatives that may increase production from this well.

- **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 pay 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 mid-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 have recompletion work performed to establish production from new intervals. Currently the four wells that comprise the Thunderbolt field, including the Eugene Island Block 108 No. 7 well, are producing at an average gross rate of 4.6 MMcfe/d, 1.3 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 late 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 3). Average current gross production for the well totals approximately 13.7 MMcfe/d, 1.2 MMcfe/d net to our retained interest after the sale.

Exploration Arrangement with El Paso

In May 2002, we entered into a farm-out agreement with El Paso for four of our shallow-water, high-risk, high-potential, deep-gas prospects. 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 four prospects until aggregate production from the prospects reaches 100 Bcfe, net to the program's interests. After aggregate production of 100 Bcfe, ownership of 50 percent would revert to us.

- **"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. As a result, we recorded a $5.3 million charge to exploration expense to recognize the impairment of a portion of the leasehold acquisition costs relating to the prospect (Note 1). In accordance with the exploration arrangement, we did not incur any drilling costs for the well. We have $4.0 million of remaining leasehold acquisition costs relating to our rights in the Hornung prospect, which is located on four offshore blocks covering 20,000 gross acres. Two of the four leases comprising the Hornung prospect are scheduled to expire in mid-2003. Recovery of this remaining leasehold acquisition cost is dependent upon El Paso or others pursuing and successfully drilling additional prospects on this exploration acreage. Evaluation of the Hornung prospect continues and drilling of an additional exploratory well to further delineate the zones shown in the first well is being considered.

- **"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 well, which was drilled to a measured depth of approximately 22,000 feet, was evaluated with wireline logs and formation tests indicating significant intervals of hydrocarbon pay. Based on the flow test, we believe that the well has the potential of producing over 60 MMcf of gas and 4,900 barrels of condensate per day. The JB Mountain prospect is expected to be brought on production in the second quarter of 2003. Plans for a second JB Mountain well are being developed.

- **"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.

- **"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 has been drilled to a measured depth of approximately 12,500 feet. The well has a planned depth of approximately 18,700 feet and is 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.

Other

- **Main Pass Block 299.** We acquired the Main Pass oil operations as part of our acquisition of Freeport Sulphur in November 1998. As of December 31, 2002, cumulative gross production from the Main Pass oil operations totaled approximately 43.8 MMBbls. The Main Pass field was shut-in during February 2001 to perform certain 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 interest. See "Disposition of Oil and Gas Properties" and "Sulphur Operations - Formation of Joint Venture" below.

- **Louisiana State Lease 340 No. 2.** In February 2001, drilling commenced on the Louisiana State Lease 340 (Mound Point) No. 2 exploratory well. The well reached a depth of 18,704 feet in August 2001 and logged a gross 50-foot interval between 18,560 feet and 18,610 feet, which by wireline log analysis was interpreted to be a potentially hydrocarbon-bearing accumulation with no indicated water level. In addition to this 50-foot interval, the well also encountered a laminated sand section in an interval from 16,890 feet to 17,275 feet, which log calculations indicate may contain hydrocarbons. In January 2002, the well was perforated and flowed at various rates from 10 to 20 MMcf/d. The well was initially flowing free of water; however, the cement that isolates the hydrocarbon-bearing sands failed and the water from the sands above the perforated zone quickly encroached the well. Flow testing confirmed the 50-foot interval that had been logged as potentially hydrocarbon bearing contains natural gas and has excellent porosity. In late March 2002, we commenced remedial operations at the well. The procedure was completed as planned; however, the well continued to produce significant amounts of water. The well has been temporarily abandoned while we evaluate further alternatives, including the evaluation of the drilling results of the well currently being drilled at the Mound Point Offset well.

- **Garden Banks Block 228.** On December 22, 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. As a result, we recorded a charge of $0.1 million to exploration expense at December 31, 2002 for the related drilling cost incurred through that date, and we will record an additional charge to exploration expense totaling $0.8 million for the remaining drilling costs incurred during the first quarter of 2003.

- **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. We retained a 5 percent overriding royalty interest, which will increase to 10 percent after aggregate production exceeds an additional 12 Bcf. Production from the field re-commenced during the first quarter of 2003. Currently the field is producing at 11.1 MMcfe/d, 0.6 Mmcfe/d net to us.

Near-Term Exploration Activities

We continually evaluate our undeveloped properties to identify prospects with attractive economic potential. The table below sets forth approximate information with respect to exploration prospects we have identified to drill, subject to obtaining the required additional financing, including through third party participation. Any additional exploratory wells we drill during 2003 will also be dependent on our continuing technical and economic evaluation of the prospects and the availability of financing.

We are currently engaged in discussions with industry participants regarding the funding of these prospects' drilling costs through farm-out or other exploration arrangements. Under these arrangements, we would expect to retain a potentially significant reversionary interest in any successful properties. 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	Planned Depth of Well[b]
	(%)	(%)	(feet)	(feet)
Eugene Island Blocks 212/213 (Phoenix)	33.3	23.4	100	22,000
Vermilion Block 208 (Lombardi Deep)	75.0	60.3	115	19,000
Louisiana State Lease 340 (Mound Point - Horst Block) [c]	30.4	22.0	10	18,700
Eugene Island Block 193 (Deep Tern Miocene)	53.4	42.3	90	20,000
Garden Banks Blocks 537/580/625 (Raven/Gunnison)	100.0	76.2	2,300	18,500
South Marsh Island Block 183 (Blackhawk) [d]	100.0	56.2	360	17,000
South Marsh Island Block 217 (Tiger Shoal) [c,e]	100.0	38.8	10	18,500

a. Interests as of March 12, 2003.
b. Planned target measured depth, which is subject to change.
c. Prospect is subject to election by El Paso for inclusion in exploration arrangement. See "Exploration Arrangement with El Paso."
d. Assumes a 100 percent working interest before casing point, which would be reduced to 70 percent after casing point. The net revenue interest would remain unchanged at 56.2 percent.
e. Assumes a 100 percent working interest before casing point, which would reduce to 55 percent after casing point. The net revenue interest for the prospect would remain unchanged at 38.8 percent. Interests are subject to change upon certain participation elections by third parties.

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 the 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 terminated (Notes 3 and 10), 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. 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 – Sale of Oil and Gas Properties" located in Items 7. and 7A., and Notes 3 and 10 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 "Sulphur Operations - Formation of Joint Venture."

Oil and Gas Reserves. *The following table summarizes our estimated proved reserves of natural gas (MMcf)* and oil (barrels) at December 31, 2002 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
8,822	5,161	411,645	167,321

We sold a substantial portion of our proved reserves in 2002, as described above. The table above does not include estimated proved developed reserves of approximately 1.9 million barrels of oil related to our 33.3 percent interest in K-Mc I. No proved reserves are attributable to our potential reversionary interests, including JB Mountain. 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, which may be substantial, in estimates of proved reserves. 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 12 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, 2002. 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, 2002 for each property. The weighted average of these prices for all our properties with proved reserves (excluding Main Pass) were $31.42 per barrel of oil and $4.99 per Mcf for gas.

	Proved Developed	Proved Undeveloped	Total Proved
		(in thousands)	
Estimated undiscounted future net cash flows before income taxes:	$ 36,263	$ 14,297	$ 50,560
Present value of estimated future net cash flows before income taxes:	$ 27,906	$ 12,581	$ 40,487

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 12 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,		
	2002	2001	2000
Net gas production (Mcf)[a]	5,851,300	11,136,800	8,291,000
Net crude oil and condensate production, excluding Main Pass (Bbls)[a,b]	124,700	342,800	190,100
Net crude oil production from Main Pass (Bbls)[c]	1,001,900	993,300	961,500
Sales prices:			
Natural gas (per Mcf)	$ 3.00	$ 3.59	$ 3.52
Crude oil and condensate, excluding Main Pass (per Bbl)[d]	$24.24	$24.62	$30.66
Crude oil from Main Pass (per Bbl)	$22.03	$21.07	$23.85
Production (lifting) costs[e]			
Per barrel for Main Pass[f]	$13.98	$19.66	$10.69
Per Mcfe for other properties[g]	$ 1.09	$ 1.13	$ 1.52

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 196,100 barrels of oil and condensate in 2001.
b. The amount during 2002 includes approximately 26,100 equivalent barrels of oil and condensate associated with $0.9 million of plant product revenues received for the value of such products recovered from the processing of our natural gas production. In 2001 our oil and condensate production included 81,100 equivalent barrels of oil associated with $3.0 million of plant product revenues.
c. We sold our interests in the oil producing assets at Main Pass on December 15, 2002 to K-Mc I.
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 includes 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 completely. 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 $1.2 million, or $0.19 per Mcfe, in 2002, $6.5 million, or $0.47 per Mcfe, in 2001 and $2.7 million, or $0.29 per Mcfe, in 2000.

Acreage. The following table shows the oil and gas acreage in which we held interests as of December 31, 2002. The table does not include the approximate 160,000 gross acres associated with our offshore exploration agreement with Texaco, on which we have rights to conduct exploration activities. 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 100,000 gross acres attributable to our potential reversionary interests (see "Exploration 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.

	Developed		Undeveloped	
	Gross Acres	Net Acres	Gross Acres	Net Acres
Offshore (federal waters)	38,751	23,140	76,918	52,875
Onshore Louisiana and Texas	-	-	1,884	1,199
Total at December 31, 2002	38,751	23,140	78,802	54,074

Unless extended, our offshore exploration agreement with Texaco will expire on January 1, 2004, at which time our right to continue to identify prospects and drill to earn leasehold interests not previously earned will expire, except for those prospects as to which we have committed to drill an exploration well. Further, approximately 30% of the approximate 160,000 gross acres subject to our agreement with Texaco have lease expiration dates prior to January 1, 2004. Also, approximately 40% of our undeveloped acres listed in the table above have lease expiration dates prior to January 1, 2004. Finally, of the approximate 100,000 gross acres attributable to our potential reversionary interests, approximately 15% have lease expiration dates prior to January 1, 2004. None of the leases relating to our JB Mountain prospect at South Marsh Island Block 223 or at our Mound Point prospect at Louisiana State Lease 340 have near term expirations, although additional drilling will be required to maintain our rights to portions of this acreage. For more information regarding our acreage position see Notes 5 and 11.

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:

	2002		2001		2000	
	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Productive	2	0.854[a]	3	1.710	6	3.669
Dry	1	0.400[b]	4	2.234	5	4.258
In-progress	2	0.776[c]	1	0.304	3	1.721
Total	5	2.030	8	4.248	14	9.648
Development						
Productive	-	-	-	-	2	1.330
Dry	-	-	-	-	-	-
Total	-	-	-	-	2	1.330

a. Includes 0.550 net interest attributable to the ownership interest in the JB Mountain well that is part of our exploration arrangement with El Paso. The other productive well during 2002 was the Louisiana State Lease 340 No. 2 well.
b. Reflects reversionary interest in the Hornung well.
c. Includes 0.570 reversionary net interest in the Lighthouse Point-Deep well. This well was evaluated to be non-productive subsequent to December 31, 2002 and has been plugged and abandoned. The other "in-progress" well, Garden Bank Block 228 (Cyprus) was also determined to be non-productive subsequent to December 31, 2002 and has been plugged and abandoned.

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.

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 new sulphur services joint venture to be 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 with respect to the 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 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."

We received gross cash proceeds totaling $58.0 million upon the closing of the transactions. We used the proceeds from the sale, after payment of certain working capital items and transaction costs, to repay a substantial portion of the borrowings outstanding under our sulphur credit facility.

Formation of Joint Venture. In October 2002, we announced the formation of an alliance with K1 USA Ventures, Inc., a subsidiary of K1 Ventures Limited (collectively K1), which will pursue the acquisition of energy-related businesses by combining the financial resources and expertise of K1 with our experience in the energy sector for the purpose of identifying high quality opportunities we believe are now available at attractive values. We will manage the business activities of the new alliance, which we call K-Mc Energy Ventures.

On December 16, 2002, we and K1 formed K-Mc I, which acquired our Main Pass oil production facilities. K-Mc I, which is owned 66.7 percent by K1 and 33.3 percent by us, also has the option, at K1's election, to acquire our remaining Main Pass facilities to be the basis for potential new business activities using the site's infrastructure. We will receive a total of $13.0 million in proceeds from the transaction, which will be used to fully fund the Phase I reclamation costs at Main Pass.

The new enterprise will continue the efforts previously initiated by us to pursue the use of the Main Pass facilities as a support hub for energy development and production projects in the Gulf of Mexico. The surface platforms and related structures at Main Pass, together with the two-mile diameter caprock and salt dome, have significant capacity and potential for a variety of commercial activities. Potential alternative uses may include the disposal of nonhazardous waste from offshore oil and gas drilling activities; a hub for receiving deepwater vessels transporting oil and gas production, including compressed natural gas and liquefied natural gas; and cavern storage facilities for natural gas and oil. The permitting process for waste disposal at Main Pass, which began in late-2000, is now nearing completion, and permitting activities are ongoing relating to other alternative uses.

Sulphur Assets. Our remaining sulphur assets primarily reflect our Port Sulphur facility, which is a combined liquid storage tank farm and stockpile area for solid sulphur with capacity to store 110,000 long tons of liquid sulphur and 1.3 million long tons of solid sulphur. 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. We have accrued $8.3 million of estimated reclamation obligations associated with this terminal as a result of its use in our former sulphur operations.

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 Fabricators Inc. (OSFI), see "Exit From Sulphur Operations," and "Environmental" in Items 7. and 7A. of this Form 10-K.

Our Freeport Sulphur 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. Under a contractual arrangement, the original leaseholder was responsible for reimbursing 50 percent of Freeport Sulphur's reclamation costs associated with the Caminada mine (Note 7). In February 2002, we reached an agreement with OSFI to provide for the reclamation and removal of the Caminada mine and related facilities. Work commenced during March 2002 and is now complete. For a summary of our agreements with OSFI, see "Exit From Sulphur Operations- Progress Towards Resolution of Sulphur Reclamation Obligations" in Items 7. and 7A., and Note 2 of this on Form 10-K.

Freeport Sulphur'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. We had $9.5 million of accrued reclamation costs for Grand Ecaille at December 31, 2002.

Freeport Sulphur 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. We have accrued amounts reflecting our current estimates of related future reclamation costs. 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 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."

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. These include the regulation of 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, 2002, we had interests in 24 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 orders pursuant to 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 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 by April 25, 2003. We are working toward resolving our sulphur reclamation issues as evidenced by the substantial progress being made on the reclamation of certain facilities at the Main Pass mine and the completion of the reclamation activities at the Caminada mine (see "Exit from Sulphur Operations – Progress Towards Resolution of Sulphur Reclamation Obligations" in Items 7. and 7A. of this Form 10-K and Note 2). We currently must provide supplemental bonding for any 100 percent-owned property. We have no properties currently fitting this criterion, except for its West Cameron Block 624 field which is in the process of being abandoned. Under some circumstances, the MMS may 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.

Effective June 1, 2001, the MMS amended its regulations governing the calculation of royalties and the valuation of crude oil produced from federal leases. This rule modifies the valuation procedures for both arm's-length and non-arm's-length crude oil transactions; eliminates posted prices as a measure of value and relies, instead, on arm's-length sales prices and spot market prices as market value indicators; and amends the procedures for determining value from the sale of federal royalty oil. We believe that this rule will not have a material impact on our financial condition, liquidity, or 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 potential pollution resulting from our operations. We believe that our operations substantially comply with applicable environmental laws. See "Risk Factors."

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 the owner or operator of the site or sites where the release occurred 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. 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 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 Sulphur 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. 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, 2002, we had 18 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, 2002, we incurred $2.2 million of expenses under the services agreement compared to $10.6 million in 2001. The decrease 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 2002 (Note 8). We expect our costs under the FM Services contract to approximate $2.2 million in 2003.

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 financial plan to address our liquidity issues and our business plan for 2003; statements regarding our need for, and the availability of, financing; our ability to satisfy the MMS reclamation obligations with respect to Main Pass; our ability to arrange for additional funding of our exploration activities with respect to our prospects; 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 other environmental issues.

Forward-looking statements are based on our 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 the actual results or 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.

As a result of adverse business conditions with our sulphur operations and significant nonproductive exploratory drilling costs, we faced significant liquidity issues in 2002. We successfully implemented our business plan to address these issues during 2002 and we continue to seek additional funding for our future exploration activities.

We entered into a farm-out agreement with El Paso to fund the exploration and development for four of our prospects. We are seeking to enter into additional farm-out or other arrangements with other companies but cannot assure you that we will succeed in entering into these arrangements. Farm-out or similar arrangements will reduce our share of any future revenues associated with our exploration prospects. Moreover, we will not have an 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 they will result in an increase in our proved oil and gas reserves or, if they do result in an increase, when that 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 and convertible preferred 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 $104.8 million in 2001, $34.9 million in 2000, $2.8 million in 1999 and $17.6 million in 1998. No assurances 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 have significant reclamation obligations at Main Pass. We have entered into an agreement with OSFI to dismantle and remove (or reclaim) our sulphur facilities at Main Pass, which is intended to satisfy our significant reclamation obligations with respect to those facilities. If OSFI were not to perform its obligations under the agreement and our reclamation obligations are not otherwise satisfied, we will remain liable for the reclamation obligations, which could be detrimental to our ability to continue to conduct our operations. For a more detailed discussion of our sulphur reclamation obligations, see "Sulphur Operations – Sulphur Reclamation Obligations" above.

In addition to our Main Pass reclamation obligations, we are responsible for reclamation obligations as well as other obligations relating to our former sulphur operations. In December 1997, we assumed responsibility for potential liabilities, including environmental liabilities, associated with the prior conduct of the businesses contributed by Phosphate Resource Partners to our predecessor. 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. Moreover, the new laws or actions by governmental agencies could result in significant additional reclamation costs for us.

We are subject to certain indemnification obligations with respect to the sulphur transportation and terminaling assets that we sold to a joint venture owned by Savage and IMC Global in June 2002, including certain environmental issues. We are also subject to certain indemnification obligations with respect to the sulphur operations previously engaged in by us or our predecessor companies. In addition, we also 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. For more information regarding these obligations, see "Sulphur Operations – Sale of Sulphur Assets."

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. We cannot assure you that our current or future accruals for reclamation costs will be sufficient to fully cover the costs.

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 find, develop or produce additional reserves 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 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.

The future financial results of our oil and gas business are difficult to forecast, primarily because the results of our exploration strategy are unpredictable. We currently have five properties in production, excluding Main Pass. 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 future 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.

Our exploration acreage position includes a significant number of leases that require near term successful drilling to preserve our rights. No assurance can be given that funding will be available for drilling the prospects that we have identified as potentially suitable for drilling.

Because a significant part of our reserves and production is concentrated in a small number of offshore properties, production problems or significant changes in reserve estimates related to any one of those properties could have a material impact on our business. Our current reserves and production primarily come from our 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.

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, remedial and abandonment costs, 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 upon 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, 2002, without any adjustment to normalize those prices and costs based on variations over time either before or after that date. Actual future prices and costs may be materially higher or lower. Future net cash flows also will be affected by factors such 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 farm-out partners or third-party operators could adversely affect the exploration and development of our prospects. We entered into a farm-out agreement with El Paso to fund the exploration and development costs for four of our prospects and we are currently seeking to enter into similar arrangements with other companies with respect to the other 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 and co-owners of our properties may lead to their attempting to delay or slow down the pace of drilling or project development to a point that may be detrimental to the project.

In addition, our farm-out partners and working interest 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 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 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 deterioration in our exploration results. A writedown could adversely affect the prices of our securities.

We follow 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 have been discovered. If proved reserves are not discovered within 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. This type of charge will reduce our stockholders' equity.

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

In addition, in view of the terrorist attacks in the United States on September 11, 2001, it is possible that further acts of terrorism may be directed against United States properties of companies such as ours.

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 some for damages caused by war or acts of terrorism. Moreover, our insurance coverages are subject to coverage limits, deductibles and other conditions. The occurrence of an event that is not fully covered by insurance could adversely effect our financial condition and results of operations.

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 our activities in 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 in 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.

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 impact 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 regulation is likely to continue. The enactment of stricter legislation or the adoption of stricter regulation 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 insurance 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 may be subject to liability or may lose the privilege to continue exploration or production activities upon substantial portions of our properties if certain environmental damages occur.

The Oil Pollution Act of 1990 imposes a variety of regulations 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 impact on us.

Other Factors

The U.S military intervention in Iraq, the terrorist attacks in the United States on September 11, 2001, the potential for additional future terrorist acts and the growing tensions between the U.S. and North Korea 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. The attacks and the resulting economic, political and social uncertainties, including the potential for further terrorist acts, have caused the premiums charged for our insurance coverages 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 at this time.

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 2000, and for each of the years in the two-year period 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 2000 and 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 Services 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. 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 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 to the Supreme Court of the State of Delaware. We will continue to defend this action vigorously.

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 12, 2003, 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	64	Co-Chairman of the Board
Richard C. Adkerson	56	Co-Chairman of the Board, President and Chief Executive Officer
C. Howard Murrish	62	Vice Chairman of the Board and Executive Vice President
Glenn A. Kleinert	60	Executive Vice President and Director
Nancy D. Parmelee	51	Senior Vice President, Chief Financial Officer and Secretary
Kathleen L. Quirk	39	Senior Vice President and Treasurer
John G. Amato	59	General Counsel

James R. Moffett has served as our Co-Chairman of the Board since November 1998. From 1994 to November 1998 he served as Co-Chairman of the Board of McMoRan Oil & Gas Co. From November 1997 to November 1998 he also served as Co-Chairman of the Board of Freeport Sulphur. Mr. Moffett has also served as the Chairman of the Board and Chief Executive Officer of Freeport-McMoRan Copper & Gold Inc. (FCX) since July 1995, and as Chairman of the Board of FCX since May 1992. Mr. Moffett served as Chairman of the Board of Freeport-McMoRan Inc. from September 1984 until December 1997. 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, President and Chief Executive Officer since November 1998. From April 1994 to November 1998 he was Co-Chairman of the Board and Chief Executive Officer of McMoRan Oil & Gas. From November 1997 to November 1998 he was Vice Chairman of the Board of Freeport Sulphur. Mr. Adkerson has also served as President of FCX since April 1997 and as Chief Financial Officer since October 2000. Mr. Adkerson served as Executive Vice President of FCX from July 1995 to April 1997, and as Senior Vice President of FCX from February 1994 to July 1995. Mr. Adkerson served as Vice Chairman of Freeport-McMoRan Inc. until December 1997.

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

Glenn A. Kleinert has served as Executive Vice President of McMoRan since May 2001. 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 1994 until 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 September 1998 through August 1999. She was appointed as Secretary of McMoRan in January 2000. Ms. Parmelee has served as Assistant Controller of FCX since July 1994. She also served as Vice President and Controller - Operations Accounting of Freeport-McMoRan Inc. from November 1996 to December 1997 and as Assistant Controller from August 1993 to November 1996.

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 Vice President and Treasurer of FCX since February 2000 and previously served as Assistant Treasurer from November 1997 to February 1999 and as Vice President from February 1999 to February 2000. Ms. Quirk has served as Vice President of Freeport-McMoRan Sulphur LLC since February 1999 and previously served as Treasurer from November 1998 to February 1999. She has also served as Vice President of McMoRan Oil & Gas LLC since July 2000.

John G. Amato has served as our General Counsel since November 1998. Mr. Amato served as General Counsel to McMoRan Oil & Gas from April 1994 to November 1998, to Freeport Sulphur from November 1997 to November 1998, and to Stratus Properties Inc. from August 1995 to August 1998. Prior to August 1995, Mr. Amato served as General Counsel of FCX and to Freeport-McMoRan Inc. Mr. Amato 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.

	2002		2001	
	High	Low	High	Low
First Quarter	$6.35	$3.20	$17.50	$12.15
Second Quarter	4.50	3.35	15.00	12.50
Third Quarter	4.40	2.65	14.75	4.80
Fourth Quarter	5.40	2.54	7.53	4.60

As of March 12, 2003 there were approximately 9,000 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.

Equity Compensation Plan Information

The following table presents information as of December 31, 2002 regarding compensation plans of the company under which our common stock may be issued to employees and non-employees as compensation. In addition to the 2003 Stock Incentive Plan, which is subject to approval of the our stockholders at the annual meeting of stockholders to be held on May 1, 2003, the company has five equity compensation plans with currently outstanding awards. These five additional plans have been previously approved by our stockholders, and are: the 1998 Stock Option Plan for Non-Employee Directors, the Adjusted Stock Award Plan, the 1998 Stock Option Plan, the 2000 Stock Incentive Plan and the 2001 Stock Incentive Plan.

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	3,393,211	$14.81	263,500(1)
Equity compensation plans not approved by security holders	—	—	—
Total..................	3,393,211	$14.81	263,500(1)

(1) As of December 31, 2002, there were 70,125 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 of the shares of common stock. In addition, there were 36,125 shares remaining available for future issuance under the 2000 Stock Incentive Plan and 106,250 shares remaining available for future issuance under the 2001 Stock Incentive Plan, all of which 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 restricted stock or "other stock-based" awards.

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, 2002. We became a publicly traded entity on November 17, 1998, when McMoRan Oil & Gas Co. (MOXY) and Freeport-McMoRan Sulphur Inc. (Freeport Sulphur) (see Item 8. Note 1 of "Notes to Financial Statements") combined their operations. This transaction was accounted for as a purchase, with MOXY as the acquiring entity. Accordingly, the information presented below for periods prior to November 17, 1998 reflects only the historical financial and operating data attributable to MOXY. Financial and operating data relating to the assets acquired from Freeport Sulphur are included on and after November 17, 1998. During 2002, we effectively terminated our involvement in sulphur business activities as more fully discussed in "Exit from Sulphur Operations" below and Note 2. 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."

	2002	2001	2000	1999	1998
Financial Data	(Financial Data in thousands, except per share amounts)				
Years Ended December 31:					
Revenues	$ 43,768	$ 72,972	$ 58,468	$ 54,344	$ 21,626
Exploration expenses	13,259	61,831	53,975	6,411	14,533
Gain on sale of oil and gas properties	44,141[a]	-	43,212[a]	3,105	447
Operating income (loss)	17,942	(104,917)	920	(4,019)	(18,664)
Income (loss) from continuing operations	18,544	(104,801)	(34,859)	(2,804)	(17,588)
Income (loss) from discontinued operations	(503)[b]	(43,260)[b]	(96,649)[b]	2,913	(528)
Net income (loss) applicable to common stock	17,041	(148,061)	(131,508)	109	(18,116)
Basic net income (loss) per share of common stock: [a]					
Continuing operations	1.09	(6.60)	(2.35)	(0.21)	(1.90)
Discontinued operations	(0.03)	(2.73)	(6.53)	0.22	(0.06)
Basic net income (loss) per share	1.06	(9.33)	(8.88)	0.01	(1.96)
Diluted net income (loss) per share of common stock:					
Continuing operations	0.93	(6.60)	(2.35)	(0.21)	(1.90)
Discontinued operations	(0.02)	(2.73)	(6.53)	0.22	(0.06)
Diluted net income (loss) per share	$ 0.91	$ (9.33)	$ (8.88)	$ 0.01	$ (1.96)
Average common shares outstanding					
Basic	16,010	15,869	14,806	13,385	9,230
Diluted	19,879[c]	15,869	14,806	13,385	9,230
At December 31:					
Working capital (deficit)	$ 5,077	$ (88,145)	$ (50,024)	$ (3,108)	$ 20,980
Property, plant and equipment, net	37,895	98,519	116,231	97,359	82,804
Sulphur business assets	355[d]	54,607	72,977	114,254	122,391
Total assets	72,448	189,686	299,324	301,281	320,388
Debt, including current portion	-	104,657	46,000	14,000	-
Mandatorily redeemable convertible preferred stock	33,773	-	-	-	-
Stockholders' equity (deficit)	$ (64,431)	$ (87,772)	$ 59,177	$ 155,071	$ 178,800

a. Includes sale of three properties in February 2002 ($29.2 million) (Note 3), the disposition of our West Cameron Block 616 field ($0.8 million) and the sale of Main Pass Block 299 in December 2002 ($14.1 million). Amount during 2000 includes our sales of Brazos Blocks A-19 and A-26 ($40.1 million) and Vermilion Block 408 ($3.1 million).
b. 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 Main Pass and a $4.0 million loss on the disposal of the sulphur transportation and terminaling assets (Note 2). 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 liability for certain sulphur retiree 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 (Note 2).
c. Includes the assumed conversion of McMoRan's 5% Convertible Preferred Stock into approximately 3.9 million shares (Notes 1 and 3).
d. Reflects sale of sulphur assets in June 2002.

	2002	2001	2000	1999	1998
Operating Data					
Sales Volumes:					
Gas (thousand cubic feet, or Mcf)	5,851,300[a]	11,136,800[a]	8,291,000	14,026,000	8,634,100
Oil, excluding Main Pass (barrels)	124,700[b]	342,800[b]	190,100	251,000	101,400
Oil from Main Pass (barrels)[c]	1,001,900	993,300	961,500	1,102,600	202,700
Plant products (equivalent barrels)[d]	26,100	81,100	-	-	-
Sulphur (long tons)	822,900	2,127,300	2,643,800	2,973,100	386,600
Average realization:					
Gas (per Mcf)	$ 3.00	$ 3.59	$ 3.52	$ 2.30	$ 2.14
Oil, excluding Main Pass (barrels)	24.24	24.62	30.66	17.85	14.01
Oil from Main Pass (barrels)	22.03	21.07	23.85	15.50	8.60
Sulphur (per long ton)	37.44	33.60	53.78	63.16	62.40

a. Sales volumes associated with the properties sold in February 2002 (Note 3) 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 2).
d. During 2002 our revenues included $0.9 million of proceeds associated with plant products (ethane, propane, butane, etc.). During 2001, our revenues associated with plant products totaled $3.0 million.

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

OVERVIEW

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 were also engaged in the purchasing, transporting, terminaling, processing and marketing of recovered sulphur through mid-June 2002, when we exited that business (Note 1).

BUSINESS PLAN IMPLEMENTATION

Our primary objective during 2002 was to address significant liquidity issues resulting from adverse business conditions affecting our former sulphur operations and significant nonproductive exploratory drilling and related costs incurred during 2000 and 2001 and to provide funding for oil and gas exploration activities. To enable us to accomplish our business plan and meet our financial obligations, we developed a financial plan requiring the achievement of various objectives. During 2002 we:

- sold three oil and gas properties for $60 million and repaid all of the debt outstanding under our previous oil and gas credit facility, which was then terminated;

- sold substantially all the assets used in our sulphur transportation and terminaling business and used the gross proceeds of $58 million to repay a substantial portion of our former sulphur credit facility and to partially fund our remaining sulphur working capital requirements;

- completed a $35 million public offering of mandatorily redeemable convertible preferred stock and used a portion of the $33.7 million of net proceeds to repay the remaining sulphur related bank debt, with the remaining funds available for our working capital requirements and for other general corporate purposes;

- entered into a fixed price contract under which we completed the dismantlement, removal and reclamation of the sulphur facilities at the Caminada mine and made substantial progress towards completing the reclamation of the Main Pass Block 299 (Main Pass) sulphur facilities not essential for use in the contemplated future businesses at the site (Phase I);

- entered into a farm-out agreement with El Paso Production Company (El Paso), a subsidiary of El Paso Corporation, to provide funding for four of our high-potential, deep-gas exploratory prospects; three of the four wells in the El Paso arrangement have been drilled yielding one discovery; a fourth well commenced in February 2003; and

- formed an alliance with K1 USA Ventures Inc., a subsidiary of K1 Ventures Limited (collectively K1), to pursue acquisitions of energy-related businesses. K-Mc Venture I LLC (K-Mc I), the initial joint venture between K1 and us, acquired our Main Pass oil producing assets. This transaction will provide the $13.0 million required to fund the Phase I reclamation costs and K1 will provide, if necessary, certain bonding assurances to the Minerals Management Service (MMS) for all the structures K-Mc I acquired.

Additional information regarding the above transactions is provided within "Exit From Sulphur Operations" and "Capital Resources and Liquidity" below and Notes 2 and 3. All subsequent references to "Notes" refer to Notes to Consolidated Financial Statements located in Item 8. of this Form 10-K. As a result of the above transactions, we repaid over $100 million of debt during 2002 and as of December 31, 2002 had positive working capital and $14.3 million of unrestricted cash available for our operations. We have also reduced our reclamation obligations by over $35 million during 2002, reflecting reductions in both our sulphur ($25 million) and oil and gas ($10 million) reclamation obligations. As a result of the formation of the K-Mc I joint venture, we secured $13 million to fund the remaining Phase I reclamation activities at Main Pass. See "Risk Factors" included elsewhere in this Form 10-K.

While McMoRan's current cash flows continue to be sensitive to market, operational and financial risks, management believes current oil and gas market conditions and projected production levels from McMoRan's existing producing properties, among other factors, will enable McMoRan to continue to fund its operations and meet its obligations during 2003.

Over the longer-term, McMoRan must develop financial resources and secure financing for its operations through the discovery, development and production of oil and gas reserves, the identification and exploitation of new business opportunities involving its Main Pass alliance with K1 or otherwise. McMoRan believes its recent successful oil and gas exploration results, together with the significant exploration potential for its remaining acreage position and its opportunities to participate in new business development in the energy industry through its affiliation with K1, including the Main Pass alliance, position the company to enable it to achieve these goals. During 2003 McMoRan will continue to pursue additional arrangements with other industry participants to drill prospects management has identified on its significant acreage position, and will be actively involved with K1 in assessing potential additional business opportunities. The ultimate outcome of these efforts is subject to various uncertainties, many of which are beyond McMoRan's control, including oil and gas prices, oil and gas production rates, exploration results and reliance on third parties to conduct exploration and development activities on our current prospects, among other factors. While McMoRan cannot ensure the ultimate success of these efforts, management believes that the resolution of the significant uncertainties McMoRan faced at the beginning of 2002, together with the current activities described above, provide significant opportunities to achieve the company's overall business objectives.

McMoRan's current independent auditors have considered its present financial condition and issued their report on McMoRan's 2002 consolidated financial statements without any qualification or reference to uncertainties regarding its ability to continue as a going concern.

EXPLORATION ACTIVITIES

Drilling Update

In May 2002, we entered into an exploration arrangement with El Paso through a farm-out transaction covering four of our shallow-water, high-risk, high-potential, deep-gas prospects on 100,000 gross acres in the Gulf of Mexico. Under the program, El Paso is funding all of our 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 reaches 100 billion cubic feet of gas equivalent (Bcfe). After aggregate production of 100 Bcfe, ownership of 50 percent of the program's interests would revert back to us.

For the status of the four prospects in the exploration arrangement with El Paso see "Oil and Gas Operations – Exploration Arrangement with El Paso" located in Items 1. and 2. of this Form 10-K.

In late 2002, we also commenced drilling the "Cyprus" exploratory well outside of the El Paso arrangement. For its status see "Oil and Gas Operations – Other" located in Items 1. and 2. of this Form 10-K.

We are pursuing additional farm-out or other exploration arrangements with oil and gas industry participants for other prospects. 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

At December 31, 2002, our acreage position included exploration and production rights covering 88 leases, including six associated with our potential reversionary interests, encompassing 376,412 gross acres and 196,127 net acres. Over the past two years, our exploration team has undertaken an intensive process to evaluate our substantial acreage position from a technical standpoint and this evaluation has resulted in an inventory of over 20 prospects being identified, including deep exploration targets for natural gas accumulations in the shallow waters of the Gulf of Mexico near existing production infrastructure. For more information regarding our acreage position see Notes 5 and 11 and "Oil and Gas Operations – Acreage" in Items 1. and 2 of this Form 10-K.

Production Update

First quarter 2003 production rates, excluding production from Main Pass 299, are estimated to approximate 7 MMcfe per day and were affected by complications associated with successful remedial activities at two of our properties and premature depletion of a producing zone at a third property. Remedial activities currently under way at Vermilion Block 160 and Thunderbolt are expected to result in improved production levels, with total production estimated to average approximately 9 MMcfe per day for the remainder of 2003. Efforts are ongoing to identify opportunities to increase production levels.

FORMATION OF JOINT VENTURE

In October 2002, we announced the formation of an alliance with K1, which will pursue the acquisition of energy-related businesses and combines the financial resources and expertise of K1 with our experience in the energy sector to identify high quality opportunities we believe are now available at attractive values. We will manage the business activities of the new alliance, which we call K-Mc Energy Ventures.

On December 16, 2002, we and K1 formed K-Mc I, which acquired our Main Pass oil production facilities and at the election of K1, we will contribute other Main Pass infrastructure assets required to support the new business activities currently being pursued at the site. K-Mc I is owned 66.7 percent by K1 and 33.3 percent by us. We will receive a total of $13 million in proceeds from the transaction, which will be used to fully fund the Phase I reclamation costs at Main Pass. These facilities are currently in the process of being dismantled pursuant to the previously announced fixed cost contract with OSFI (see "Progress Towards Resolution of Sulphur Reclamation Obligations" below). In addition, K1 will provide credit support, if necessary, for the new venture in an amount up to $10 million to provide financial assistance for K-Mc I's bonding requirements with the MMS covering the Main Pass oil assets. Also in connection with the transaction, K1 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 and, upon their election to participate in the future business activities, would receive additional warrants to purchase an additional 0.76 million shares of McMoRan common stock at a price of $5.25 per share. Also, if K1 elects to have K-Mc I acquire the additional Main Pass infrastructure assets required to support the new business activities, K1 will provide additional financial assistance, if necessary, to cover up to an additional $10 million of MMS bonding requirements covering these assets. 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 value of the stock warrants issued to K1. We are accounting for our investment in the joint venture using the equity method.

The new enterprise will continue the efforts previously initiated by us to pursue the use of the Main Pass facilities as a support hub for energy development and production projects in the Gulf of Mexico. The surface platforms and related structures at Main Pass, together with the two-mile diameter caprock and salt dome, have significant capacity and potential for a variety of commercial activities. The potential alternative uses may include the disposal of nonhazardous waste from offshore oil and gas drilling activities; a hub for receiving deepwater vessels transporting oil and gas production, including compressed natural gas and liquefied natural gas; and cavern storage facilities to store natural gas and oil. The permitting process for waste disposal at Main Pass, which began in late-2000, is now nearing completion, and permitting activities are ongoing relating to other alternative uses.

EXIT FROM SULPHUR OPERATIONS

Sale of Sulphur Transportation and Terminaling 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 new sulphur joint venture owned equally by IMC Global Inc. (IMC Global) and Savage Industries Inc. In connection with this transaction, we settled all outstanding disputes between IMC Global and its subsidiaries and us. 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 10). At December 31, 2002, approximately $0.9 million of the 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 the retained environmental obligations further discussed below. We recorded an aggregate loss of $4.0 million during 2002 associated with the disposal of the sulphur business assets, including the estimated loss on the disposal of certain rail cars.

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 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 and $13.7 million during 2000 associated with these reclamation activities. During the first quarter of 2002, we entered into contractual agreements with a third party to dismantle and remove the remaining Main Pass and Caminada sulphur facilities (see "Progress Towards Resolution of Sulphur Reclamation Obligations" below).

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 Sulphur 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 April 25, 2003, in recognition of Freeport Sulphur's progress in completing reclamation activities at its Caminada mine facilities and in the completion of a significant portion of the reclamation activities covering the structures and facilities at Main Pass not essential to the planned future businesses at the site (Phase I), as further discussed immediately below and in "Formation of Joint Venture." Under the K-Mc I joint venture, K1 will provide credit support, if necessary, to cover up to $10 million of MMS bonding requirements covering the Main Pass oil assets. Additionally, if K1 elects to have K-Mc I acquire the additional assets for the planned future business activities, K1 will provide additional financial assistance, if necessary, to cover up to an additional $10 million of MMS bonding requirements covering these assets. Any decision to further extend the compliance date for the trust agreement is solely at the MMS' discretion. Management intends to continue to cooperate fully with the MMS as Freeport Sulphur follows through on the actions referred to above to ultimately resolve its sulphur reclamation obligations.

Progress Towards Resolution of Sulphur Reclamation Obligations

In the first quarter of 2002, we entered into contractual agreements 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. OSFI commenced its reclamation activities at the Caminada mine in March 2002 and its activities at the site are now complete. During the second quarter of 2002, we recorded a $5.0 million gain, included in the caption "Loss from discontinued operations" in the accompanying consolidated statements of operations, associated with the substantial resolution of the Caminada sulphur reclamation obligations and the related conveyance of certain assets to OSFI, as further discussed below.

OSFI commenced its initial Phase I reclamation work at Main Pass in August 2002. As of December 31, 2002, OSFI had completed approximately 40 percent of the Phase I reclamation work and we expect the completion of all Phase I work by mid-year 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 (see "MMS Bonding Requirement Status" above). When we 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 third party and payment of the sales proceeds to OSFI as it completed Main Pass sulphur reclamation activities. In August 2002, we amended our contract with OSFI to clarify certain aspects, including specifying values for the reclamation of the Phase I structures at Main Pass. Under the terms of this arrangement, OSFI will receive $13 million for its Phase I reclamation activities. We recorded a $5.2 million gain, included in "Loss from discontinued operations" in the accompanying consolidated statements of operations, in connection with the reduction in the estimated Phase I reclamation costs from $18.2 million to $13.0 million based on the contract with OSFI. In addition, we have been engaged in on-going activities to obtain regulatory approval from the MMS to enable the establishment of a new business enterprise that would use part of the Main Pass sulphur facilities and infrastructure. At the time we entered into the contractual agreements with OSFI, we contemplated that a third party would establish and operate this new business enterprise and that we would retain a negotiated share of the revenues or profits from this new business enterprise, which we would share with OSFI.

As of December 31, 2002, we had received $3.4 million of the $13.0 million of proceeds from K-Mc I, which represents reimbursement of the costs we had previously paid to OSFI in connection with its Phase I reclamation activities at Main Pass prior to the formation of K-Mc I. We have subsequently received an additional $2.3 million of these proceeds, which we used to fund OSFI's reclamation activities subsequent to December 31, 2002. K-Mc I will pay us the remaining $7.3 million of proceeds as we are required to fund OSFI's remaining Phase I reclamation activities. We currently anticipate that we will receive and pay this amount by mid-year 2003.

We believe the transactions described above will resolve our sulphur bonding issues with the MMS. These transactions are expected to significantly reduce or eliminate our accrued Main Pass reclamation obligations in which case we would recognize additional gains. Because these matters involve inherent uncertainties, including matters beyond our control, no assurances can be given that these transactions will be completed as contemplated.

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 oil and gas operations and the discontinued operations (in millions).

	For Year Ended December 31,		
	2002	2001	2000
Continuing oil and gas operations			
Operating	$ (7.1)	$ 6.6	$ 27.3
Investing	46.4	(105.8)	(11.3)
Financing	(16.6)	50.3	32.9
Discontinued operations			
Operating	$ (11.6)	$ (14.8)	$ (37.1)
Investing	58.6	6.3	5.1
Financing	(55.0)	9.0	32.0
Total cash flow			
Operating	$ (18.7)	$ (8.1)	$ (9.8)
Investing	105.0	(99.5)	(6.1)
Financing	(71.6)	59.3	64.9

Comparison of Year-To-Year Cash Flows

Operating

Our cash flow from our continuing oil and gas operating activities decreased in 2002 as compared to 2001 reflecting our lower revenues primarily from the disposition of oil and gas properties during the first half of 2002 and working capital changes offset in part by lower geological and geophysical and other exploration costs, which totaled $4.2 million in 2002 and $18.3 million in 2001. The decrease in our oil and gas operating cash flows in 2001 as compared to 2000 can be attributed primarily to working capital changes, reclamation expenditures, primarily for Vermilion Block 144, and lower operating results.

Operating cash flow from our discontinued operations increased in 2002 as compared to 2001 primarily reflecting lower reclamation costs, which totaled $5.3 million in 2002 and $11.4 million in 2001. The decrease in reclamation costs reflects the signing of fixed cost contracts with OSFI to perform the reclamation work at the Caminada and Main Pass sulphur mines and related facilities. Our operating cash flow from discontinued operations reflects a reduction of the cash used in 2001 as compared to 2000, primarily reflecting improved sulphur operating results following the cessation of the sulphur mining operations at Main Pass in August 2000 and a reduction in sulphur reclamation expenditures, which totaled $16.9 million in 2000 and $11.4 million in 2001.

Investing

Our exploration and development capital expenditures for our continuing oil and gas operations totaled $17.0 million during 2002, which primarily reflects 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 during 2002 (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 of our oil and gas properties (see "Sale of Oil and Gas Properties" below) and the receipt of the initial $3.4 million of $13.0 million of proceeds associated with the transaction forming K-Mc I.

Our exploration and 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" below). Capital expenditures during 2001 also included the development costs associated with our discoveries made in 2000, the exploratory well drilling costs and the related completion costs associated with the Eugene Island Block 97 No. 2 and 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 unit and the Eugene Island Block 193 C-1 well. We also sold two oil and gas leases for $1.3 million during 2001.

Our exploration and development and other capital expenditures totaled $46.2 million during 2000. This total includes capitalized drilling costs of $17.0 million associated primarily with our six exploratory discoveries during 2000 and $29.2 million of unsuccessful drilling costs charged to expense. During 2000, we expended a total of $39.8 million to purchase oil and gas leasehold acreage, including $37.8 million for the Shell lease acquisition (Note 5). We also sold various operating assets during 2000 for a total of $74.7 million, including our interests in Brazos Blocks A-19 and A-26 for $66.5 million and Vermilion Block 408 for $6.2 million.

Our cash flows from our discontinued operations during 2002 included the $58.0 million of gross proceeds we received in June 2002 in connection with the transactions that resulted in our exit from the recovered sulphur business. The discontinued operations' investing cash flow also includes proceeds of $0.6 million from a sale of miscellaneous Main Pass sulphur facility assets.

During the fourth quarter of 2001, our discontinued operations sold one of its 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.

In June 2001, Freeport Sulphur acquired Homestake's 16.7 percent interest in Main Pass and assumed their estimated $7.1 million portion of the remaining estimated reclamation costs at the Main Pass sulphur mine, and the related sulphur and oil facilities. Our consolidated operating results include this acquired interest subsequent to June 1, 2001.

The investing activities of our discontinued operations provided cash of $5.1 million during 2000, including the sale of the remaining assets and real estate at the Culberson sulphur mine in west Texas, and the sale of the Grand Isle base (see "Results of Operations – Discontinued Sulphur Operations" below).

Financing

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 (see "Equity Offering" below). 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 activity in 2000 reflects our equity offering proceeds totaling $50.3 million, partially offset by purchases of shares of our common stock (see below) and deferred financing and other costs.

The financing activities of our discontinued operations reflects 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 the sulphur transportation and terminaling assets (see "Exit From Sulphur Operations – Sale of Sulphur Transportation and Terminaling Assets" above) and the completion of our equity 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. Our discontinued operations' financing activities during 2000 included $32.0 million of net borrowings under the sulphur credit facility, which were used to fund our sulphur operations and continuing reclamation activities and to terminate a sulphur-related obligation (Note 11).

In 1999, our Board of Directors authorized an open market share purchase program for up to two million shares of our common stock. In March 2000, the Board authorized the purchase of up to an additional 500,000 shares of our common stock, increasing the total shares authorized under our share purchase program to 2.5 million. As of December 31, 2002, we had purchased 2,244,635 shares of our common stock for $41.6 million, an average of $18.56 per share. No share purchases were made during either 2002 or 2001. The share purchases during 2000 totaled 799,900 shares for $15.2 million, an average of $19.00 per share. Although we have no near-term plans to initiate any additional share purchases, any future share purchases will be dependent upon many factors, including our cash flows and financial position, the price of our common stock, our operating results, and general economic and market conditions.

Sale of Oil and Gas Properties

In February 2002, we sold certain of our oil and gas properties for $60.0 million. Under terms of the sales agreement, we sold our interests in Vermilion Block 196, Main Pass Blocks 86/97, and 80 percent of our interests in Ship Shoal Block 296. We have retained a reversionary interest in these properties equal to 75 percent of the transferred interests following payout of the $60 million plus a specified annual rate of return. Whether or not payout ultimately occurs will depend upon future production and future market prices of both natural gas and oil, among other factors. Upon closing, we used the proceeds to repay all borrowings outstanding on the oil and gas credit facility ($51.7 million), which then was terminated. We subsequently negotiated a new credit facility (see "Revolving Bank Credit Facilities" below). In December 2002, we finalized a transaction forming the K-Mc I joint venture, which acquired our interests in the Main Pass oil producing assets.

Equity Offering

In June 2002, we completed a $35 million public offering of 1.4 million shares of our 5% mandatorily redeemable preferred convertible preferred stock. Each $25 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 our common stock, which is equivalent to $4.81 per share representing a 20 percent premium over our common stock closing price on June 17, 2002. We can redeem the preferred stock after June 30, 2007 and must redeem the stock by June 30, 2012. Any redemption we make must be made in cash. We paid dividends totaling $0.9 million during the second half of 2002.

Revolving Bank Credit Facilities

We repaid over $100 million in outstanding debt during 2002. As a result at December 31, 2002, we had no remaining debt outstanding.

<u>Oil and Gas Credit Facility</u> We had $49.7 million of borrowings outstanding on our oil and gas revolving bank credit facility at December 31, 2001. In February 2002, we repaid all our remaining borrowings outstanding under this oil and gas credit facility ($51.7 million) following the sale of three of our oil and gas properties for $60.0 million. The credit facilities were terminated after repayment of the amounts outstanding.

In July 2002, we entered into a one-year, $10.0 million revolving bank credit facility with Hibernia National Bank, which at December 31, 2002 provided us with up to $2.0 million of borrowing capacity. The amount available under the facility is reduced by $0.5 million per month (Note 10).

<u>Sulphur Credit Facility</u> At December 31, 2001, our borrowings under the sulphur credit facility totaled $55.0 million. In June 2002, following the sale of our sulphur transportation and terminaling assets and the completion of our public equity offering, we repaid all remaining borrowings under the facility ($58.5 million) and the facility was then terminated.

Contractual Obligations and Commitments

As further described in Note 11, we are currently obligated to make minimum annual contractual payments under long-term contracts and operating leases, substantially all of which are associated with leases for rail cars previously used in our sulphur transportation services and office space in Houston, Texas that was previously occupied by an independent company that provided us geological and geophysical costs on an exclusive basis (Note 11). A substantial majority of our former lease obligations were assumed by the Gulf Sulphur Services or by IMC Global in June 2002.

In 2003, we will receive sublease income of $1.1 million from Gulf Sulphur Services and IMC Global, representing full reimbursement of our rail car lease expense. We intend to seek an extension of such sublease terms or otherwise assign our rail car leases.

Freeport Sulphur's recorded contractual obligation to reimburse certain former sulphur retirees' medical costs (Note 11) is expected to require payments currently estimated to total $47.9 million before considering the present value effect of the timing of these payments. We expect to fund these other long-term contractual obligations with operating cash flows, future financing transactions and asset sales as necessary.

A summary of our remaining minimum annual lease payments (excluding related sublease income) and our expected payments under this contractual obligation is as follows (in millions):

	Lease Payments	Medical Costs	Total
2003	$ 1.3	$ 1.4	$ 2.7
2004	0.9	1.4	2.3
2005	0.9	2.9	3.8
2006	0.7	3.0	3.7
2007	0.6	3.0	3.6
Thereafter	2.3	36.2	38.5
Total	$ 6.7	$ 47.9	$54.6

RESULTS OF OPERATIONS

As a result of our exit from the sulphur business, our remaining continuing operating segment is oil and gas exploration and production activities. See "Exit From Sulphur Operations" above for information regarding our former sulphur segment. The oil and gas segment includes all oil and gas exploration and production operations of MOXY, as well as Freeport Sulphur's oil operations at Main Pass, which we have recently sold in connection with the formation of K-Mc I. We generated operating income totaling $17.9 million during 2002, including $44.1 million of gains associated with the disposition of certain oil and gas properties 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.

Oil and Gas Operations

We use the successful efforts accounting method for our oil and gas operations, under which our exploration costs, other than costs of drilling successfully and in progress exploratory wells, are charged to expense as incurred (Note 1).

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

	2002	2001
Oil and gas revenues – prior year	$ 72,942	$ 58,468
Increase (decrease)		
Price realizations:		
Oil	338	(4,008)
Gas	(3,452)	780
Sales volumes:		
Oil	(4,605)	4,609
Gas	(18,975)	10,017
Plant products revenue	(2,131)	2,999
Other	(349)	77
Oil and gas revenues - current year [a]	$ 43,768	$ 72,942

a. Current year oil and gas revenues include $2.4 million associated with the properties sold in February 2002 (See "Capital Resources and Liquidity – Sale of Oil and Gas Properties" above). Oil and gas revenues for 2002 also include $0.3 million of revenues from West Cameron Block 616, which we farmed out to a third party in June 2002.

2002 Compared with 2001

Our 2002 revenues decreased approximately 40 percent from 2001 revenues primarily reflecting substantially decreased production volumes of both gas (47 percent from 2001) 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 ($3.00 per Mcf) from those received in 2001 ($3.59 per Mcf) partially offset by a slight increase (1 percent) in the average per barrel price we received from our oil sales during 2002 ($22.28 per barrel) compared to those received in 2001 ($21.98 per barrel). 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 effectiveness of certain recompletion 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" above) 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 the third and fourth quarters of 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 "Exit From Sulphur Operations – Progress Towards Resolution of Sulphur Reclamation Obligations" above).

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 (ethane, propane, butane, etc.) recovered from the processing of our natural gas. Our plant product revenues during 2001 totaled $3.0 million associated with 81,100 barrels of equivalent barrels of oil and condensate. The decrease in our plant products is primarily the result of the sale of two of our 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. See "2001 Compared with 2000" below for information regarding our 2001 workover costs; 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.

For more information regarding our operating activities related to our oil and gas fields, see Items 1. and 2. "Business and Properties" located elsewhere in this Form 10-K.

We follow the unit-of-production method for calculating depletion, depreciation and amortization expense for our oil and gas properties (Note 1). 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 reflects 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 below) totaling $7.6 million during 2002 compared with $39.1 million in 2001. Our impairment charges for 2002 include 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. See "2001 Compared with 2000" below for a detail of our 2001 impairment charges; and

3) The use of higher unit-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.

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 an impairment is deemed to have occurred. Conditions affecting current and estimated future cash flows which could cause such impairment charges to be recorded include, but are not limited to, lower anticipated future oil and gas prices, increased production, development and reclamation costs and downward revisions to previous 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 included in future periods' results of operations.

Our exploration expenses will fluctuate in future periods based on the structure of our arrangements to drill exploratory wells (i.e. whether exploratory costs are financed by other participants or by us), and 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. Includes a $5.3 million charge to impair 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 (see "Exploration Activities" above). 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 exploratory well at Garden Bank Block 228 was nonproductive, we were required under current accounting standards to charge our share of the well drilling costs incurred through December 31, 2002 to exploration expense for the year then ended. Accordingly, our exploration expense total includes $0.1 million of costs associated with the well (see "Exploration Activities" 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.

2001 Compared with 2000

Our 2001 revenues increased approximately 25 percent over 2000 revenues because of substantially increased production volumes (34 percent over 2000) resulting from the commencement of production from four properties discovered during 2000: Eugene Island Block 97 (Thunderbolt); Eugene Island Block 193 (North Tern Deep); Vermilion Block 196 (Lombardi) and Ship Shoal Block 296 (Raptor) (see "Oil and Gas Operations - Oil and Gas Properties" located in Items 1. and 2. "Business and Properties" of this Form 10-K). Increased revenues during 2001 also reflect our acquisition of Homestake's 16.7 percent interest in the Main Pass field in June 2001 (see "Capital Resources and Liquidity" above). Revenues during 2001 were adversely affected by a lower average realization for oil, which decreased by 12 percent to $21.98 per barrel in 2001 from $24.98 per barrel in 2000. The average annual realization for natural gas in 2001 ($3.59 per Mcf) remained relatively unchanged from the average realization in 2000 ($3.52 per Mcf). This small change in annual average realizations does not fully reflect the extreme volatility in natural gas market prices during these periods, which were at record highs during the second half of 2000 but declined sharply throughout 2001.

Production and delivery costs totaled $35.0 million during 2001 compared with $24.6 million during 2000. The increase reflects the following:

1) Increased production from the four properties that commenced production in mid-year 2001 (as discussed above);
2) Well workover costs totaled $6.5 million in 2001 compared with $2.7 million during 2000. During 2001, we performed well workovers at the Vermilion Block 160 field unit and Vermilion Block 160 No. 4 well (BJ-1) and at Eugene Island Blocks 193/208/215; and

3) Increased production costs at Main Pass, resulting from the acquisition of Homestake's 16.7 percent interest in the field and from higher platform and equipment repair and maintenance costs, which included $1.9 million incurred during February 2001.

Our depletion, depreciation and amortization expense totaled $65.9 million in 2001 compared with $32.4 million during 2000. The increase reflects the substantially higher production volumes achieved during 2001 resulting from the commencement of production from the four properties discussed above. Our depletion, depreciation and amortization expense during 2001 also includes impairment charges totaling $39.1 million to reduce the asset carrying values of the West Cameron Block 616 ($19.1 million) and West Cameron Block 624 ($4.1 million) fields and the Louisiana State Lease 340 (Mound Point) No. 2 well ($15.9 million) to their respective estimated fair values (see "2002 Compared with 2001" above). During the fourth quarter of 2000, we recorded a $14.0 million impairment charge to reduce the asset carrying value of the West Cameron Block 616 field to its then estimated fair value.

Our exploration expenses were substantial during both 2001 and 2000 because of our expanded exploration activities during the two years. Summarized exploration expenses are as follows (in millions):

	Years Ended December 31, 2001	Years Ended December 31, 2000
Geological and geophysical, Including 3-D seismic purchases	$ 15.7	$ 22.0
Dry hole costs	43.5[a]	29.2[b]
Other	2.6	2.8
	$ 61.8	$ 54.0

a. 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.
b. Includes the nonproductive exploratory well costs associated with the State Lease 210 No. 6 (Grass Island Prospect), Green Canyon Block 90 No. 1, Garden Banks Block 580 No. 1 and Vermilion Block 144 No. 3 wells. Also includes the incremental unsuccessful exploratory costs associated with drilling the Eugene Island Block 97 No. 1 well to depths greater than its original successful shallower objective.

In July 2000, we sold Brazos Blocks A-19 and A-26 for $70 million, $66.5 million net to our interests, resulting in a gain of $40.1 million. In September 2000, we sold Vermilion Block 408 for $6.5 million, $6.2 million net to our interest, resulting in a gain of $3.1 million.

Our 2000 operating results also include a $23.3 million gain associated with the settlement of our business interruption insurance claim for Brazos Block A-19. We settled this claim with our insurers in December 2000 and collected approximately $21.0 million of the settlement proceeds as of December 31, 2000. The remainder of the proceeds were collected in the first quarter of 2001.

Other Financial Results

Our general and administrative expenses totaled $6.4 million in 2002, $15.1 million in 2001 and $13.0 million in 2000. The decrease in 2002 from 2001 reflects reduced administrative costs incurred 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 two Co-Chairmen not receiving any cash compensation during 2002 (Note 8). The decrease in our general and administrative expense during 2002 also reflects the substantial reduction of our costs under the FM Services contract (Note 6), which totaled $2.2 million in 2002 and $10.6 million in 2001, which includes $0.2 million in 2002 and $1.5 million in 2001 associated with the discontinued operations. The increase in general and administrative expenses in 2001 from 2000 primarily reflects costs associated with our increased oil and gas exploration and development activities during that two-year period.

Interest expense, net of capitalized interest, totaled $0.7 million in 2002, $0.4 million for 2001 and $3.1 million for 2000. We capitalized interest of $0.3 million during 2002 and $1.5 million during 2001. We did not capitalize any interest during 2000. Our interest expense reflects borrowings on our bank credit facilities beginning in the fourth quarter of 1999. We incurred these borrowings to fund our lease acquisition from Shell (Note 5), exploration expenditures, purchases of our common stock and working capital. We repaid all of our borrowings outstanding under our oil and gas credit facility in July 2000 upon receipt of the proceeds from the sale of Brazos Blocks A-19 and A-26 (see above). We had no borrowings under our oil and gas credit facility at December 31,

2000. 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" above and Note 10.

Other income totaled $1.3 million in 2002, $0.5 million in 2001 and $2.3 million in 2000. 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, with the remaining $0.2 million of other income representing interest income on our cash balance. The amount of our other non-operating income during 2001 reflects the gain on the sale of two leases with the remainder representing interest income. The non-operating income amount in 2000 consisted of gains of $1.4 million from miscellaneous asset sales, with the remainder representing interest income.

In connection with the decision to exit active participation in our sulphur operations in 2000, we recorded a $34.9 million charge to our deferred tax valuation allowance, which eliminated our net deferred tax asset that related primarily to our sulphur transportation and terminaling business. This determination was based upon updated estimates of projected operating results.

Discontinued Sulphur Operations

During 2002 we completed our strategic plan of exiting the sulphur business by selling substantially all our remaining sulphur assets in June 2002 (see "Exit from Sulphur Operations" above and Note 2). We had previously ceased all our sulphur-mining activities in August 2000. As a result of our 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 2. We have not provided a comparison of 2002 to 2001 as the variance between the two years is almost entirely the result of 2002 having less than six months of operations compared to an entire year of operations during 2001.

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

	2002	2001	2000
Sulphur revenues - prior year	$ 71,483	$ 143,309	$ 189,687
Increase (decrease)			
Price realizations	3,160	(42,929)	(24,799)
Sales volumes	(43,828)	(27,777)	(20,799)
Other	(5)	(1,120)	(780)
Sulphur revenues – current year	$ 30,810	$ 71,483	$ 143,309

2001 Compared with 2000

Our sulphur revenues decreased by 50 percent during 2001 when compared to 2000. The variance in revenues between the two years reflects a reduction in sales volumes of approximately 20 percent and a decrease in average sulphur realizations of 38 percent. In 2001, our average realization for sulphur sold totaled $33.60 per long ton compared to $53.78 per long ton in 2000. We sold a total of 2.1 million long tons of sulphur in 2001 compared to 2.6 million long tons in 2000. The reduced sales volumes and average realizations for sulphur during 2001 primarily reflect significantly reduced demand because of depressed conditions in the historically cyclical phosphate fertilizer industry, the principal consumer of sulphur. Several large phosphate fertilizer producers implemented production curtailments in late 2000 and early 2001. These curtailments contributed to the decrease in sulphur prices from an average of $64.50 per ton in the fourth quarter of 2000 to an average market price of $27.50 per ton in Tampa, Florida, through the third quarter of 2001, a decrease of 57 percent. The average sulphur market price increased to $32.50 per ton during the fourth quarter of 2001 as demand for sulphur increased as phosphate fertilizer producers partially restored their production levels and increased by an additional $8.00 per ton during the first quarter of 2002 to an average market price of approximately $40.50 per ton.

Sulphur production and delivery costs totaled $78.1 million during 2001 and $154.4 million during 2000. The production and delivery costs during 2000 included $11.5 million of charges associated with our planned exit from active participation in the sulphur business. The production and delivery costs during 2000 also include $63.0 million of costs associated with the production from the Main Pass sulphur mine, which was closed in August 2000 (see "Exit From Sulphur Operations" above). The decrease also reflects the reduced volumes sold during the first half of 2001 as a result of the major U.S. phosphate fertilizer producers' production curtailments, including IMC Global's closure of all its Mississippi River region plants. During the third quarter of 2001 and throughout the remainder of the year, sulphur sales benefited from IMC Global's decision to resume production from two of its Louisiana plants in July 2001. Our production and delivery costs during 2001 included charges totaling $10.0 million to adjust our sulphur inventory carrying amounts to its net realizable value. We incurred similar charges totaling $5.2 million to reduce the sulphur inventory carrying costs to its then net realizable value during the first half of 2000.

Sulphur depletion, depreciation and amortization expense totaled $15.3 million during 2001 compared with $84.3 million during 2000. The decrease primarily reflects the $79.9 million we recorded in connection with our decisions to close the Main Pass sulphur mine and to our planned exit from active participation in the sulphur business (see below). The decrease was partially offset by a $10.8 million charge we recorded at December 31, 2001, to reduce our sulphur transportation and terminaling assets to their then estimated net realizable value.

Because of significantly negative market and operating conditions, as well as our plan to exit active participation in the sulphur business, our 2000 results included noncash charges totaling $86.0 million to adjust our sulphur segment assets and liabilities to their estimated fair values. These noncash charges included $20.1 million to write off the remaining book value of the Main Pass sulphur mine; $25.2 million for the writedown of the book value of other mining-related assets, including specialized marine equipment used in handling mined sulphur ($19.1 million) and material and supplies inventory ($6.1 million), to their estimated recoverable values; and $40.7 million for remaining unaccrued estimated mine reclamation costs resulting from our decision to cease sulphur mining operations. Additional estimated charges of $7.5 million, including employee-related costs, were included as a components of our production and delivery costs ($5.4 million) and general and administrative expenses ($2.1 million) in 2000.

Other Sulphur Matters

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). In addition, 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 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 $1.7 million during 2002 and $0.8 million in both 2001 and 2000.

The $3.8 million of other income during 2001 generated by the sulphur operations included the receipt of the final $3.9 million of proceeds from the 1990 sale of a sulphur distillation plant. The $11.8 million of other income received by our sulphur operations during 2000 was generated from the sale of nonoperating assets (see below).

In the third quarter of 2000, we terminated a sulphur-related obligation assumed in our 1995 purchase of certain sulphur transportation and terminaling assets by paying $6.0 million and placing $3.5 million in an escrow account to fund assumed environmental liabilities associated with the acquired assets. We have assumed these liabilities and believe the escrowed amount is sufficient to fund any future related costs. The restricted escrowed cash is considered a long-term asset and is recorded in "Other assets" on the accompanying consolidated balance sheets.

During 2000 we completed the reclamation of the Culberson, Texas mine, which ceased production on June 30, 1999. During the first half of 2000, we recorded gains of $2.4 million from sale of various assets at the Culberson mine. In the fourth quarter of 2000, we sold all of our remaining interests in the mine and its related assets for approximately $3.5 million, which resulted in a $3.2 million gain. Also during the fourth quarter of 2000, we sold the Grand Isle base, which was previously used for offshore logistics support for our sulphur operations, for $1.2 million, recognizing a gain for the same amount. In November 2000, we were informed by the U.S. State Department of a $5.0 million partial settlement of our $8.9 million claim resulting from the sale of a sulphur distillation plant in 1990. We recorded $4.9 million as a receivable at December 31, 2000, with the entire amount being collected in January, 2001. We received the remaining $3.9 million of proceeds associated with this claim in March 2001.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Management's Discussion and Analysis of our financial condition and results of operations are 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 "Exit From Sulphur Operations – Sale of Sulphur Transportation and Terminaling Assets" above). The estimated reclamation costs associated with our oil and gas properties approximated $9.5 million, and through December 31, 2002, we had accrued $8.0 million for these costs on a field-by-field basis using the unit-of-production method over the related estimated proved reserves. For a discussion of the estimated proved reserves see "Depletion, Depreciation and Amortization" below.

Our sulphur reclamation obligations are associated with our former sulphur mining operations. In June 2002 we made a decision to cease all mining operations, which resulted in us recording a charge that fully accrued 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 a substantial portion of the reclamation work at the Main Pass facilities is currently in progress (see "Exit From Sulphur Operations – Progress Towards Resolution of Sulphur Reclamation Obligations"). At December 31, 2002, our accrued sulphur reclamation obligations totaled $38.5 million, with $8.1 million in current liabilities associated with the ongoing work at Main Pass. The Main Pass reclamation work currently in progress will be paid for with proceeds from our disposition of the Main Pass oil producing assets (see "Formation of Joint Venture" above).

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. Under SFAS 143, the cumulative effect of adopting the new standard as of January 1, 2003 for all existing asset retirement obligations, asset retirement costs and related accumulated depreciation is required to be reflected in earnings as a separate item.

The accounting estimates related to reclamation costs are critical accounting estimates because 1) the cost of these obligations are 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 currently estimated retirement obligations associated with our oil and gas operations would approximate $9 million and for our former sulphur operations would approximate $32 million. The total of these current estimates is less than the estimates on which the obligations accrued through December 31, 2002 were based because of the effect of applying weighted probabilities to the multiple scenarios used in this calculation. To calculate the fair value of the currently 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. A change of one percent in the inflation rate used results in an approximate $1 million change in the discounted present value costs.

At January 1, 2003, we estimated the fair value of our total assets retirement obligations to be approximately $26 million, of which approximately $7 million relates to our oil and gas operations. We will record 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 million to their estimated fair value. The net difference between our previously recorded reclamation obligations and the amounts estimated under SFAS 143 totaled approximately $20 million, which will be recognized as a cumulative effect gain of a change of accounting principle. 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 unit-of-production method based on 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, 2002, we estimate that our annual depletion, depreciation and amortization expense for 2003 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 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 11 percent in 2002, decreasing ratably annually until reaching 5 percent in 2009. A one-percentage point increase or decrease in assumed health care cost trend rates would not have a significant impact on our net income. See Notes 8 and 11 for additional information. 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 effect 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 2003, a change of $0.10 per Mcf in the average prices realized on natural gas sales would have an approximate $0.4 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).

Our current credit facility has a variable interest rate, which exposes us to interest rate risk. At the present time we do not hedge our exposure to fluctuations in interest rates. We currently have no debt outstanding and do not anticipate that we will borrow any funds in the near-term.

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.

As discussed in "Exit From Sulphur Operations" above, we have fully accrued the remaining estimated costs to 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 signing of the OSFI fixed cost contracts and the completion of their Caminada mine reclamation activities. Reclamation activities are currently in progress at Main Pass where OSFI had completed approximately 40 percent of the removal of the Phase I facilities as of December 31, 2002 (see "Exit From Sulphur Operations – Progress Towards Resolution of Sulphur Reclamation Obligations" above).

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 are currently 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 have implemented a new accounting standard that has reduced both our oil and gas and sulphur reclamation obligations. These reductions will be recorded as cumulative gains on change in accounting principle in our first quarter 2003 results 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 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 contain forward-looking statements. All statements other than statements of historical fact included 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 is tested and evaluated on a regular basis by McMoRan's internal auditors, PricewaterhouseCoopers LLP. 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 consider 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 PricewaterhouseCoopers LLP meet regularly with, and have access to, this committee, with and without management present, to discuss the results of their audit work.

James R. Moffett	Richard C. Adkerson	Nancy D. Parmelee
Co-Chairman of the Board	Co-Chairman of the Board, President and Chief Executive Officer	Senior Vice President, 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 sheet of McMoRan Exploration Co. (a Delaware Corporation) as of December 31, 2002 and the related consolidated statements of operations, cash flow and changes in stockholders' equity (deficit) for the year then ended. 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 audit. The Company's financial statements as of December 31, 2001 and for the years ended December 31, 2001 and 2000 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 audit 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 audit provides a reasonable basis for our opinion.

In our opinion, the 2002 financial statements referred to above present fairly, in all material respects, the consolidated financial position of McMoRan Exploration Co. as of December 31, 2002 and the consolidated results of its operations and its cash flow for year then ended in conformity with accounting principles generally accepted in the United States.

Ernst & Young LLP

New Orleans, Louisiana
January 22, 2003

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, 2002.

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, 2002	December 31, 2001
	(In Thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents:		
Continuing operations	$ 12,907	$ -
Discontinued operations, $0.9 million restricted at December 31, 2002	2,316	500
Accounts receivable:		
Customers	3,456	5,515
Joint interest partners	348	5,197
Other	9,841	180
Product inventories	120	690
Prepaid expenses	791	270
Current assets from discontinued operations, excluding cash	449	12,477
Total current assets	30,228	24,829
Property, plant and equipment, net (Note 7)	37,895	98,519
Discontinued sulphur business assets, net (Note 2)	355	54,607
Other assets, including restricted cash of $3.5 million at December 31, 2002 and 2001 (Notes 7 and 11)	3,970	11,731
Total assets	$ 72,448	$ 189,686
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)		
Current liabilities:		
Accounts payable	$ 5,246	$ 22,230
Accrued liabilities	5,092	15,192
Borrowings outstanding on sulphur credit facility	-	55,000
Current portion of oil and gas credit facility	-	2,000
Current portion of accrued sulphur reclamation costs	8,126	-
Current portion of accrued oil and gas reclamation costs	878	398
Other current liabilities from discontinued operations	5,481	17,849
Other	328	305
Total current liabilities	25,151	112,974
Accrued oil and gas reclamation costs	7,116	18,278
Accrued sulphur reclamation costs	30,421	63,876
Long-term borrowings outstanding on oil and gas credit facility	-	47,657
Contractual postretirement obligation related to discontinued operations	21,564	19,922
Other long-term liabilities (Note 7)	18,854	14,751
Commitments and contingencies (Note 11)		
Mandatorily redeemable convertible preferred stock, net of unamortized offering costs of $1.2 million (Notes 3 and 4)	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, 18,429,402 shares and 18,194,139 shares issued and outstanding, respectively	184	182
Capital in excess of par value of common stock	308,903	302,454
Unamortized value of restricted stock units	(151)	-
Accumulated deficit	(330,770)	(347,811)
Common stock held in treasury, 2,295,900 shares, at cost	(42,597)	(42,597)
Stockholders' deficit	(64,431)	(87,772)
Total liabilities, convertible preferred stock and stockholders' equity (deficit)	$ 72,448	$ 189,686

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

McMoRan EXPLORATION CO.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2002	2001	2000
	(In Thousands, Except Per Share Amounts)		
Revenues	$ 43,768	$ 72,942	$ 58,468
Costs and expenses:			
Production and delivery costs	26,223	35,016	24,631
Depletion, depreciation and amortization expense	24,117	65,868	32,421
Exploration expenses	13,259	61,831	53,975
General and administrative expenses	6,368	15,144	12,984
Gain on sale of oil and gas properties	(44,141)	-	(43,212)
Insurance settlement gain	-	-	(23,251)
Total costs and expenses	25,826	177,859	57,548
Operating income (loss)	17,942	(104,917)	920
Interest expense, net	(704)	(357)	(3,134)
Other income, net	1,313	481	2,297
Income (loss) from operations before provision for income taxes	18,551	(104,793)	83
Provision for income taxes	(7)	(8)	(34,942)
Income (loss) from continuing operations	18,544	(104,801)	(34,859)
Loss from discontinued operations	(503)	(43,260)	(96,649)
Net income (loss)	18,041	(148,061)	(131,508)
Preferred dividends and amortization of convertible preferred stock issuance costs	(1,000)	-	-
Net income (loss) applicable to common stock	$ 17,041	$ (148,061)	$ (131,508)
Net income (loss) per share of common stock:			
Basic net income (loss) from continuing operations	$1.09	$(6.60)	$(2.35)
Basic net loss from discontinued operations	(0.03)	(2.73)	(6.53)
Basic net income (loss) per share of common stock	$1.06	$(9.33)	$(8.88)
Diluted net income (loss) from continuing operations	$0.93	$(6.60)	$(2.35)
Diluted net loss from discontinued operations	(0.02)	(2.73)	(6.53)
Diluted net income (loss) per share of common stock	$0.91	$(9.33)	$(8.88)
Average common shares outstanding:			
Basic	16,010	15,869	14,806
Diluted	19,879	15,869	14,806

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

McMoRan EXPLORATION CO.
CONSOLIDATED STATEMENTS OF CASH FLOW

	Years Ended December 31,		
	2002	2001	2000
		(In Thousands)	
Cash flow from operating activities:			
Net income (loss)	$ 18,041	$ (148,061)	$ (131,508)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Loss from discontinued operations	503	43,260	96,649
Depletion, depreciation and amortization	24,117	65,868	32,421
Exploration drilling and related expenditures	9,097	43,510	29,175
Gain on disposition of oil and gas properties	(44,141)	-	(43,212)
Gain on sale of equity investment	(1,084)	-	-
Change in deferred tax asset	-	-	34,942
Changes in assets and liabilities:			
Reclamation and mine shutdown expenditures	(752)	(2,196)	-
Other	1,854	2,149	(743)
(Increase) decrease in working capital:			
Accounts receivable	4,079	6,090	(9,038)
Accounts payable and accrued liabilities	(19,019)	(3,772)	20,151
Inventories and prepaid expenses	211	(222)	(1,561)
Net cash (used in) provided by continuing operations	(7,094)	6,626	27,276
Net cash used in discontinued sulphur operations	(11,567)	(14,752)	(37,122)
Net cash used in operating activities	(18,661)	(8,126)	(9,846)
Cash flow from investing activities:			
Exploration, development and other capital expenditures	(16,984)	(107,092)	(46,183)
Purchase of oil and gas interests	-	-	(39,793)
Proceeds from disposition of oil and gas properties	63,400	1,291	74,719
Net cash provided by (used in) continuing activities	46,416	(105,801)	(11,257)
Net cash provided by discontinued sulphur operations	58,583	6,252	5,122
Net cash provided by (used in) investing activities	104,999	(99,549)	(6,135)
Cash flow from financing activities:			
Net borrowings (repayments) on oil and gas credit facility	(49,657)	49,657	-
Net proceeds from stock offering	33,698	-	50,274
Dividends paid on convertible preferred stock	(924)	-	-
Purchases of MMR common stock	-	-	(15,282)
Other	268	612	(2,105)
Net cash (used in) provided by continuing operations	(16,615)	50,269	32,887
Net borrowings (repayments) on sulphur credit facility	(55,000)	9,000	32,000
Net cash (used in) provided by financing activities	(71,615)	59,269	64,887
Net increase (decrease) in cash and cash equivalents	14,723	(48,406)	48,906
Restricted cash of discontinued operations	(941)	-	-
Net increase (decrease) in unrestricted cash and cash equivalents	13,782	(48,406)	48,906
Cash and cash equivalents at beginning of year	500	48,906	-
Cash and cash equivalents at end of year	$ 14,282	$ 500	$ 48,906
Interest paid	$ 4,027	$ 6,973	$ 6,546
Income taxes paid	$ 7	$ 8	$ -

The accompanying notes, which include information in Notes 1, 2, 3, 5, 6, 8, 9, 11 and 14 regarding noncash transactions, are an integral part of these consolidated financial statements.

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

	Years Ended December 31,		
	2002	2001	2000
Preferred stock:			
Balance at beginning and end of year	$ -	$ -	$ -
Common stock:			
Balance at beginning of year representing 18,194,139 shares in 2002, 18,138,875 shares in 2001, and 14,229,904 shares in 2000	182	181	142
Exercised stock options representing no shares in 2002, 3,724 shares in 2001 and 73,239 shares in 2000	-	-	1
Shares issued to CLK (Note 9) representing 235,263 shares in 2002, 51,540 shares in 2001, and 35,732 shares in 2000	2	1	-
Shares issued on equity offering representing 3,800,000 shares (at $14.00 per share)	-	-	38
Balance at end of year representing 18,429,402 shares in 2002, 18,194,139 shares in 2001 and 18,138,875 shares in 2000	184	182	181
Capital in Excess of Par Value:			
Balance at beginning of year	302,454	301,343	249,625
Exercised stock options and other	268	612	982
Shares issued to CLK	934	499	500
Restricted stock unit grants	194	-	-
Issuance of stock warrants	5,053	-	-
Shares issued in equity offering	-	-	50,236
Balance at end of year	308,903	302,454	301,343
Unamortized value of restricted stock units:			
Balance beginning of year	-	-	-
Deferred compensation associated with restricted stock units (Note 1)	(194)	-	-
Amortization of related deferred compensation	43	-	-
Balance end of year	(151)	-	-
Accumulated Deficit:			
Balance at beginning of year	(347,811)	(199,750)	(68,242)
Net income (loss)	18,041	(148,061)	(131,508)
Dividends on preferred stock and amortization of issuance cost	(1,000)	-	-
Balance at end of year	(330,770)	(347,811)	(199,750)
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 2002 and 2001 and 1,444,735 shares in 2000	(42,597)	(42,597)	(26,454)
Shares purchased representing 799,900 shares in 2000	-	-	(15,196)
Tender of 51,265 shares in 2000 to exercise McMoRan stock options	-	-	(947)
Balance at end of year representing 2,295,900 shares in 2001 and 2000 and 1,444,735 shares in 1999	(42,597)	(42,597)	(42,597)
Total stockholders' equity (deficit)	$ (64,431)	$ (87,772)	$ 59,177

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Background. McMoRan Exploration Co. (McMoRan), a Delaware Corporation, became a publicly traded entity in November 1998, when McMoRan Oil & Gas Co. (MOXY) and Freeport-McMoRan Sulphur Inc. (Freeport Sulphur) combined their respective operations (the Merger). In the Merger, Freeport Sulphur's shareholders received 0.625 McMoRan common shares for each Freeport Sulphur outstanding common share or a total of 5.5 million McMoRan common shares, while MOXY's shareholders received 0.20 McMoRan common shares for each MOXY outstanding common share, or a total of 8.6 million McMoRan common shares. The Merger was reflected in McMoRan's financial statements using the purchase method of accounting with MOXY as the acquiring entity. The assets acquired and liabilities assumed from Freeport Sulphur were recorded at estimated fair values based on cash flow models and independent appraisals.

Basis of Consolidation. The consolidated financial statements of McMoRan 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 MOXY and Freeport Sulphur subsidiaries and reflects its investment in K-Mc Venture I LLC using the equity method (Note 2). 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.

Basis of Presentation. McMoRan's financial statements are prepared in accordance with accounting principles generally accepted in the United States. As a result of McMoRan's exit from the sulphur business, as evidenced by its sale of substantially all of its sulphur assets (Note 2), 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 a maturity of three months or less are considered cash equivalents (excluding restricted cash, see Note 2).

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 both 2001 and 2000. These charges, included within the caption "loss from discontinued operations" (Note 2), totaled $10.0 million during 2001 and $5.2 million during 2000. McMoRan also charged $6.1 million of sulphur material and supplies inventory to expense when it decided to cease sulphur mining operations at Main Pass Block 299 (Main Pass) in June 2000 (Note 2).

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 expensed. Acquisition costs of leases and development activities are also capitalized. Other exploration costs are charged to expense as incurred. Depletion, depreciation and amortization are determined on a field-by-field basis using the unit-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 certain 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 of $0.3 million during 2002 and $1.5 million during 2001. No interest was capitalized during 2000.

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 2).

McMoRan had previously recorded charges in June 2000 totaling $20.1 million to write off its asset carrying values for the Main Pass sulphur mine and certain related facilities to reflect the decision to cease sulphur mine production. Certain other sulphur mining-related assets were reduced by $19.1 million to their estimated net realizable values in anticipation of their being sold. Through the first quarter of 2002, at which time McMoRan entered into a definitive agreement to sell substantially all its remaining sulphur assets, depletion, depreciation and amortization expense for McMoRan's sulphur transportation logistic and marketing (transportation and terminaling) assets was calculated on a straight-line basis over an estimated 30 years for terminals and 5 to 15 years for machinery, equipment and certain transportation assets. 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 2 for more discussion regarding McMoRan's sulphur-related charges now included within the caption "Loss from discontinued operations."

Asset Impairment. Costs for unproved oil and gas properties are assessed periodically, and a loss is recognized if the properties are deemed impaired. 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.

At December 31, 2002, as a result of a downward reserve revision for our Eugene Island Block 97 field, we 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, as a result of mechanical problems encountered by the well at the West Cameron Block 624 field, 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, which covers four offshore lease blocks (Eugene Island Blocks 96/97/108/109) encompassing 20,000 gross acres. McMoRan has $4.0 million of remaining Hornung prospect leasehold acquisition costs. Recovery of this leasehold cost is dependent upon McMoRan, a current exploration partner (Note 5) or others pursuing and successfully drilling additional identified exploration opportunities on this acreage over the near term. Two of the four leases comprising the Hornung prospect are currently scheduled to expire in mid-2003. McMoRan is currently seeking an arrangement to provide for additional exploratory drilling on this prospect prior to the expiration of its lease rights.

At December 31, 2001, McMoRan's estimated undiscounted cash flows associated with its West Cameron Block 616 and West Cameron Block 624 fields were less than the related net book values of the respective properties. Accordingly, 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.

In the fourth quarter of 2000, because of a reduction of West Cameron Block 616's estimated oil and gas reserves, the net book value of this field exceeded the related estimated future undiscounted cash flows. Accordingly, a $14.0 million charge to depletion, depreciation and amortization expense was recognized that reduced the property's net book value to its then estimated fair value.

Major Customers. During 2002, McMoRan sold approximately 90 percent of its oil and gas production to three purchasers. All of McMoRan's customers are located in the United States.

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. 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.

Effective January 1, 2001, McMoRan adopted Statement of Financial Accounting Standards 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133). SFAS 133, as amended, establishes accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or liability measured at fair value. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation. The adoption of SFAS 133 did not significantly impact McMoRan's 2001 financial statements.

McMoRan's use of financial contracts to manage risks has been limited. McMoRan had no financial contracts during 2002. McMoRan's only contracts during 2001 and 2000 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 and 0.3 million barrels of oil at a cost of $2.8 million during 2000. These costs reduced McMoRan's oil revenues for each of these periods. McMoRan currently has no forward oil sales contracts or other derivative contracts.

Environmental Remediation and Compliance. 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.

Through December 31, 2002, McMoRan has 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 unit-of-production method based on estimated proved reserves of each respective field. These future expenditures are estimated based on current costs, laws and regulations. At December 31, 2002, McMoRan had $8.0 million of accrued oil and gas reclamation costs, including $0.9 million of current obligations, compared to $18.7 million of accrued oil and gas reclamation costs at December 31, 2001. 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 2).

Effective June 30, 2000, McMoRan initiated a plan to exit active participation in the sulphur business and specifically to cease production from its sulphur mining operations (Note 2). Accordingly, McMoRan recorded charges totaling $40.7 million during 2000 to accrue all remaining estimated reclamation costs related to its Main Pass sulphur mine and its related facilities. At December 31, 2002, McMoRan had $38.5 million of accrued sulphur reclamation costs, including $8.1 million of current obligations, compared to $63.9 million at December 31, 2001. See Note 2 for a discussion of McMoRan's fixed-cost contract agreements that have significantly reduced McMoRan's accrued sulphur reclamation obligations.

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. See "Reclamation and Closure Costs" below for discussion of McMoRan's adoption of a new accounting method for reclamation obligations effective January 1, 2003.

Reclamation and Closure Costs. In June 2001, the Financial Accounting Standards Board (FASB) issued 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 will adopt SFAS 143 effective January 1, 2003 and will record an estimated gain of approximately $20 million representing the cumulative effect of a change in accounting principle.

Prior to adoption of SFAS 143, estimated future reclamation and mine closure costs for McMoRan's oil and gas operations were accrued and charged to expense over the estimated life of each field using the unit-of-production method based on estimated proved reserves. Each reclamation obligation related to McMoRan's closed sulphur mines and related facilities were previously fully accrued upon their closure.

Share Purchase Program. In 1999, McMoRan's Board of Directors authorized an open market share purchase program for up to 2.0 million shares of its common stock. In March 2000, the Board authorized the purchase of up to an additional 0.5 million shares of its common stock, increasing the total shares authorized under the share purchase program to 2.5 million. McMoRan did not purchase any shares of its common stock during either 2002 or 2001. As of December 31, 2002, McMoRan had purchased 2,244,635 shares of its common stock at an average cost of $18.56 per share.

Restricted Stock. In April, 2002, under McMoRan's stock-based compensation plans (Note 8), the Board of Directors granted 50,000 restricted stock units (RSUs) that will be converted ratably into 50,000 shares of McMoRan common stock on the grant anniversary date over the next three years. Upon issuance of the RSUs, unearned compensation equivalent to the market value at the date of grant of approximately $0.2 million was recorded as deferred compensation in stockholders' equity and will be charged to expense over the three-year period. McMoRan charged approximately $43,000 of this deferred compensation to expense during 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 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,		
	2002	2001	2000
Basic income (loss) from continuing operations	17,544	(104,801)	(34,859)
Add: Preferred dividends and issuance cost amortization from assumed conversion	1,000	-	-
Diluted income (loss) from continuing operations	18,544	(104,801)	(34,859)
Loss from discontinued operations	(503)	(43,260)	(96,649)
Diluted net income (loss) applicable to common stock	$ 18,041	$ (148,061)	$ (131,508)
Weighted average common shares outstanding (Basic)	16,010	15,869	14,806
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	19,879	15,869	14,806
Diluted net income (loss) from continuing operations	$0.93	$(6.60)	$(2.35)
Diluted net income (loss) from discontinued operations	(0.02)	(2.73)	(6.53)
Diluted net income (loss) per share	$0.91	$(9.33)	$(8.88)

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 126,000 shares in 2001 and 96,000 shares in 2000.
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 3). 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.

Outstanding stock options excluded from the computation of diluted net income (loss) per share of common stock because their exercise prices were greater than the average market price of the common stock during the period are as follows:

	Years Ended December 31,		
	2002	2001	2000
Outstanding options (in thousands)	3,368	1,318	1,274
Average exercise price	$ 14.89	$ 17.44	$ 19.74

In December 2002, in connection with the formation of a joint venture (Note 2), McMoRan issued stock warrants to a third party that could be converted into 1.74 million shares of McMoRan's common stock at an exercise price of $5.25 per share. The assumed effect of the conversion of these stock warrants was excluded from the diluted net income per share calculation because the exercise price of the stock warrants exceeded the average market price of McMoRan's stock for the year.

Stock-Based Compensation Plans. As of December 31, 2002, McMoRan has four 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,		
	2002	2001	2000
Basic net income (loss) applicable to common stock, as reported	$ 17,041	$ (148,061)	$ (131,508)
Add: Stock-based employee compensation expense recorded in net income for restricted stock units	43	-	-
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards	(5,166)	(3,276)	(1,907)
Pro forma basic net income (loss) applicable to common stock	11,918	(151,337)	(133,415)
Add: preferred dividends and issuance cost amortization from assumed conversion	1,000	-	-
Pro forma diluted net income (loss) applicable to common stock	$ 12,918	$ (151,337)	$ (133,415)
Earnings (loss) per share:			
Basic – as reported	$ 1.06	$ (9.33)	$ (8.88)
Basic – pro forma	$ 0.74	$ (9.54)	$. (9.01)
Diluted – as reported	$ 0.91	$ (9.33)	$ (8.88)
Diluted – pro forma	$ 0.65	$ (9.54)	$ (9.01)

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 weighted average fair value for stock option grants was $4.00 per option in 2002, $11.38 per option in 2001 and $11.50 per option in 2000. The weighted average assumptions used include a risk-free interest rate of 5.1 percent in 2002, 5.3 percent in 2001 and 6.7 percent in 2000; expected volatility of 55 percent in 2002 and 2001 and 35 percent in 2000; no annual dividends; and an expected life of 7 years for options granted in 2002 and 10 years for all options granted before 2002. 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.

New Accounting Standards. As discussed in "Reclamation and Closure Costs" above, McMoRan adopted SFAS No. 143 on January 1, 2003. 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 Transaction," with regard to reporting the effects of a disposal of a segment of a business and will require 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.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation-Transition and Disclosure," an amendment to SFAS No. 123. The standard, which is effective immediately, provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation and amends disclosure requirements. McMoRan continues to apply APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations in accounting for its stock-based compensation; therefore, the alternative methods of transition do not apply. McMoRan has adopted the disclosure requirements of SFAS No. 148 (see "Stock-Based Compensation Plans" above).

2. SULPHUR OPERATIONS

In November 1998, McMoRan acquired Freeport Sulphur, 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 financial statements. The table below provides a summary of the discontinued results of operations for each of the three years ended December 31, 2002.

	Years Ended December 31,		
	2002	2001	2000
Revenues	$ 30,810	$ 71,483	$ 143,309
Production and delivery costs	27,484	78,136	154,362
Depletion, depreciation and amortization	646	15,269	84,334
General and administrative expenses	3,012	5,202	9,503
Postretirement health and welfare costs	1,682	14,381	835
Operating loss	(2,014)	(41,505)	(105,725)
Interest expense	(3,504)	(5,546)	(2,693)
Other income, net	4,265[a]	3,791[b]	11,769[b]
Net loss from discontinued sulphur operations	(1,253)	(43,260)	(96,649)
Gain on sale of asset [c]	750	-	-
Total loss from discontinued operations	$ (503)	$ (43,260)	$ (96,649)

a. 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 a $4.0 million loss on the disposal of the sulphur transportation and terminaling assets.
b. The amount during 2000 includes $5.6 million of gains from asset sales associated with the closed Culberson mine in west Texas, a $1.2 million gain from the sale of the Grand Isle base and $5.0 million gain associated with a prior sale of a sulphur distillation plant. The amount during 2001 includes an additional $3.9 million gain associated with the sale of the sulphur distillation plant.
c. Received $0.8 million of proceeds from the sale of an oil and gas asset that was previously written off.

Exit From Sulphur Business

Mine closure and plans to exit sulphur business. In July 2000, McMoRan undertook a plan to exit its sulphur mining operations and to sell its remaining sulphur transportation and terminaling assets. The Main Pass sulphur mine ceased production on August 31, 2000.

McMoRan recorded charges totaling $86.0 million during 2000 to adjust its sulphur assets and liabilities to their estimated fair values. These charges include $20.1 million to write off the remaining book value of the Main Pass sulphur mine; $25.2 million to reduce the book value of the mining-related assets, including certain specialized marine equipment used in handling mined sulphur ($19.1 million) and materials and supplies inventory ($6.1 million), to their estimated recoverable values; and $40.7 million to record the remaining unaccrued estimated mine reclamation costs. All of the above charges were charged to depletion, depreciation and amortization expense, except the $6.1 million reduction of materials and supplies inventory, which was recorded as production and delivery costs (see table above).

Also in 2000, McMoRan recorded a $7.5 million employee-related charge associated with its planned exit from active participation in sulphur operations. McMoRan included $5.4 million of the anticipated employee-related separation costs in production and delivery costs and the remaining $2.1 million in general and administrative expenses. This accrual included $4.7 million of employee termination charges and $2.8 million resulting from curtailments of McMoRan's retirement and post-retirement health and welfare pension plans. McMoRan paid all remaining amounts of these employee-related charges following the sale of substantially all of its remaining sulphur assets in June 2002 (see below).

Sale of Sulphur Transportation and Terminaling Assets. On June 14, 2002, Freeport Sulphur sold substantially all the assets used in its sulphur transportation and terminaling business to Gulf Sulphur Services Ltd., LLP, a new sulphur 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 10). At December 31, 2002, approximately $0.9 million of the funds from these transactions remained deposited in various restricted escrow accounts, which will be used to partially fund Freeport Sulphur's remaining sulphur working capital requirements and to provide funding for certain retained environmental obligations as further discussed below. As a result of these transactions, McMoRan's results for 2002 include a $4.0 million loss associated with the disposition of the sulphur transportation and terminaling assets, including the estimated loss on the disposal of certain rail cars, which is included in the accompanying consolidated statements of operations within "Loss from discontinued operations."

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. Freeport Sulphur's terminal facility at Port Sulphur, Louisiana was not transferred to Gulf Sulphur Services and is being marketed separately.

In connection with the preceding transactions, McMoRan has also agreed to be responsible for any historical environmental obligations relating to its sulphur transportation and terminaling assets and has 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 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. No such obligations have been identified or are believed to exist as of December 31, 2002 (Note 11).

Following is a summary of the net book value of McMoRan's sulphur assets (in thousands):

	December 31,	
	2002	2001
Transportation and terminaling[a]	$ -	$ 52,296
Other assets held for sale[b]	355	2,311
Total sulphur business assets	$ 355	$ 54,607

a. Includes assets sold in June 2002. The assets at January 1, 2001 included goodwill of $11.4 million, net of accumulated amortization of $0.6 million. McMoRan wrote off the remaining $10.8 million of goodwill at December 31, 2001 to reduce its sulphur transportation and terminaling assets to their then estimated fair value.
b. Includes certain marine equipment previously used in handling mined sulphur, the Port Sulphur, Louisiana, terminal and other miscellaneous assets. The remaining cost at December 31, 2002, primarily represents the Port Sulphur terminal.

Main Pass

In June 2001, Homestake Sulphur Company LLC (Homestake) transferred its sulphur and oil interests in Main Pass to Freeport Sulphur. Freeport Sulphur received $2.5 million in cash and Homestake's 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, estimated to total $7.1 million at the time of the acquisition. McMoRan accounted for the transaction as a purchase and began consolidating this acquired 16.7 percent 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 facilities. Freeport Sulphur negotiated an agreement with a third party to engage in commercial brine production and the storage of non-hazardous oil field wastes at Main Pass. Commercial brine production commenced in the first quarter of 2001, while the non-hazardous oil field waste storage operations are currently pending final regulatory approval by the Minerals Management Service (MMS). The agreement between McMoRan and the third party has been terminated and McMoRan has now assumed operatorship of the commercial brine operations.

In December 2002, McMoRan formed a new joint venture that acquired the Main Pass oil producing assets (see "Formation of Joint Venture" below).

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. McMoRan incurred reclamation costs totaling $9.8 million during 2001 and $13.7 million during 2000 associated with these reclamation activities. During the first quarter of 2002, McMoRan entered into contractual agreements with a third party 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 us that they were considering requiring McMoRan or Freeport Sulphur 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 April 25, 2003, in recognition of Freeport Sulphur's progress in completing reclamation activities at its Caminada mine facilities and in the completion of a significant portion of the reclamation activities covering the structures and facilities at Main Pass not essential to the planned future businesses at the site (Phase I), as further discussed immediately below and in "Formation of Joint Venture." Under the K-Mc I joint venture, K1 will provide credit support, if necessary, to cover up to $10 million of MMS bonding requirements covering the Main Pass oil assets. Additionally, if K1 elects to have K-Mc I acquire the additional assets for the planned future business activities, K1 will provide additional financial assistance, if necessary, to cover up to an additional $10 million of MMS bonding requirements covering these assets. Any decision to further extend the compliance date for the trust agreement is solely at the MMS' discretion. Management intends to continue to cooperate fully with the MMS as Freeport Sulphur follows through on the actions referred to above to ultimately resolve its sulphur reclamation obligations.

In the first quarter of 2002, Freeport Sulphur and Offshore Specialty Fabricators Inc. (OSFI) entered into contractual 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 assets to OSFI, as further discussed below. The gain on the resolution of the Caminada reclamation obligation is included in the caption "Loss from discontinued operations" in the accompanying consolidated statements of operations.

In August 2002, OSFI commenced its initial Phase I reclamation work at Main Pass. As of December 31, 2002, OSFI had completed approximately 40 percent of the Phase I reclamation work. The Phase I reclamation work is scheduled to be completed by mid-2003.

As payment of its share of these reclamation costs, Freeport Sulphur conveyed certain assets to OSFI including a supply service boat, Freeport Sulphur's dock facilities in Venice, Louisiana, and certain assets previously salvaged by Freeport Sulphur during a prior reclamation phase at Main Pass (see above). In addition to these conveyed assets, Freeport Sulphur agreed to provide to OSFI the proceeds from the sale of its economic interest in the Main Pass oil operations and certain initial payments relating to the establishment of a business enterprise using certain of the Main Pass sulphur facilities for the disposal of non-hazardous oilfield waste from offshore oil operations. In August 2002, OSFI and Freeport Sulphur amended the contract to clarify certain aspects, including specifying values for the reclamation of the Phase I sulphur structures at Main Pass. Under terms of this arrangement, OSFI would receive $13.0 million for its Phase I reclamation activities. Freeport Sulphur is funding the Phase I reclamation costs with proceeds from the joint venture transaction (see "Formation of Joint Venture" below). Freeport Sulphur recorded a $5.2 million gain during 2002 in connection with the reduction in the estimated Main Pass Phase I accrued reclamation costs from $18.2 million to $13.0 million based on the fixed contract with OSFI. The gain is included within the caption "Loss from discontinued operations" in the accompanying consolidated statements of operations and the remaining obligation for Phase I is included in current liabilities in the accompanying consolidated balance sheet at December 31, 2002.

Formation of Joint Venture

In October 2002, McMoRan and K1 USA Ventures, Inc. and K1 USA Energy Production Corporation, subsidiaries of K1 Ventures Limited (collectively K1), announced the formation of an alliance, which will pursue acquisitions of energy-related businesses by combining the financial resources of K1 with McMoRan's experience in the energy sector. McMoRan will manage the business activities of the new alliance, K-Mc Energy Ventures.

On December 16, 2002, McMoRan and K1 completed the formation of K-Mc I Venture LLC (K-Mc I), in which K1 owns 66.7 percent and McMoRan owns 33.3 percent. K-Mc I acquired McMoRan's Main Pass oil facilities. K-Mc I also has an option to acquire certain of McMoRan's remaining Main Pass facilities that will be used to pursue new business activities using the site's unique infrastructure. At the election of K1, McMoRan will transfer to K-Mc I other Main Pass infrastructure assets required to support the planned future business activities. The Phase I facilities at Main Pass are excluded from the joint venture and are currently in the process of being dismantled pursuant to the fixed cost contract with OSFI (see "Sulphur Reclamation Obligations" above).

McMoRan will receive $13.0 million of proceeds associated with the transaction and K1 has agreed to provide, if required, credit support for up to $10 million of MMS bonding requirements covering the Main Pass oil facilities. The proceeds are being received as required to fund the Phase I reclamation activities, which were approximately 40 percent complete at December 31, 2002. K1 received stock warrants to purchase approximately 1.74 million shares of McMoRan common stock at any time within five years at a price of $5.25 per share. To the extent K1 elects for K-Mc I to acquire the Main Pass infrastructure assets required to support the planned future business activities, K1 will receive additional stock warrants to purchase approximately 0.76 million shares of McMoRan common stock at a price of $5.25 per share. K1 will also provide, if required, financial assistance to K-Mc I for up to an additional $10 million in MMS bonding requirements related to the reclamation obligations for these assets. McMoRan will continue to operate the Main Pass facilities under a management agreement. 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. 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, 2002) is limited to exclude recognition of negative equity in K-Mc I as McMoRan has no required future obligations to fund K-Mc 1's operating losses, debt or reclamation obligations.

The new enterprise will continue the efforts previously initiated by McMoRan to pursue the use of the Main Pass facilities as a support hub for energy development and production projects in the Gulf of Mexico. The surface platforms and related structures at Main Pass, together with the two-mile diameter caprock and salt dome, have significant capacity and potential for a variety of commercial activities. The potential alternative uses may include the disposal of nonhazardous waste from offshore oil and gas drilling activities; a hub for receiving deepwater vessels transporting oil and gas production, including compressed natural gas and liquefied natural gas; and cavern storage facilities to store natural gas and oil. The permitting process for waste disposal at Main Pass, which began in late-2000, is now nearing completion, and permitting activities are ongoing relating to other alternative uses.

3. CAPITAL RESOURCES AND LIQUIDITY MATTERS

McMoRan faced significant financial liquidity issues entering into 2002 as a result of adverse business conditions with its sulphur operations and significant nonproductive exploratory drilling costs during 2001 and 2000. Subsequent to December 31, 2001, McMoRan took steps to address its financial liquidity requirements and developed a financial plan to provide sufficient financial resources to conduct its business. At the date McMoRan released its 2001 financial statements, certain aspects of this plan had not been completed, and inherent uncertainties existed, including uncertainties beyond McMoRan's control.

In addition to the steps discussed in Note 2 with respect to McMoRan's sulphur business and the formation of the K-Mc I joint venture, other actions taken by McMoRan subsequent to December 31, 2001 to address its financial liquidity requirements are described below.

Sale of Certain Oil and Gas Properties

On February 22, 2002, MOXY sold three of its oil and gas properties for $60.0 million. The sale was effective January 1, 2002. McMoRan sold its interest in Vermilion Block 196 and Main Pass Blocks 86/97, and 80 percent of its interest in Ship Shoal Block 296. McMoRan has retained its 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. The properties were sold subject to a 75 percent reversionary interest after a defined payout, which would occur when the purchaser receives aggregate cumulative proceeds from the properties of $60.0 million plus an agreed annual rate of return. McMoRan's current estimates of proved reserves do not include any reserves for McMoRan's reversionary interest; however, whether or not payout ultimately occurs depends primarily upon future production and future market prices of both natural gas and oil. Currently only two of the three properties sold in this transaction have production. Production has not yet commenced from Main Pass Blocks 86/97.

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 on February 22, 2002. The credit facility was then terminated (Note 10). McMoRan recorded a gain on the sale of its interests in these properties totaling $29.2 million.

Additional Capital

On June 21, 2002, McMoRan completed a $35 million public offering of 1.4 million shares of 5% mandatorily redeemable convertible preferred stock (Note 4). Proceeds received from the offering totaled $33.7 million, net of an underwriting discount of $1.1 million and $0.2 million of certain other issuance costs. As of December 31, 2002, McMoRan has amortized a total of $76,000 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 10) and is using the remaining funds for its working capital requirements and other general corporate purposes.

In July 2002, MOXY entered into a one-year, $10 million revolving bank credit facility agreement that provided it with borrowing capacity of $2.0 million at December 31, 2002 (Note 10). McMoRan has not borrowed any amounts under this facility. McMoRan may also consider the sale or other farm-out arrangements of additional oil and gas properties to raise additional capital.

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 high-potential, deep-gas 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 reaches 100 billion cubic feet of gas equivalent (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. Drilling commenced at the Hornung prospect in April 2002 and at the JB Mountain and Lighthouse Point-Deep prospect in June 2002.

In October 2002, the Hornung well's results were evaluated not to contain commercial quantities of hydrocarbons and the well was plugged and abandoned. As a result, McMoRan impaired a portion of its leasehold acquisition costs for the Hornung prospect, which is located on acreage covering four offshore blocks covering 20,000 gross acres, resulting in a $5.3 million charge to exploration expense in the third quarter of 2002. McMoRan's remaining leasehold acquisition costs associated with the Hornung prospect totaled $4.0 million at December 31, 2002. Two of the four leases comprising the Hornung prospect expire in mid-2003. McMoRan is currently in discussions with certain industry participants regarding the potential drilling of a second exploratory well at the Hornung prospect. McMoRan announced a discovery at the JB Mountain prospect in December 2002. See Note 14 for drilling results subsequent to December 31, 2002. MOXY plans to enter into additional farm-out or other exploration arrangements with El Paso and other oil and gas industry participants for other prospects.

Current Considerations

The actions taken during 2002 referred to above and in Note 2 enabled McMoRan to repay all its previous outstanding indebtedness, resolve a majority of both its near- and long-term sulphur reclamation obligations and provide third-party funding for several of its deep-gas exploration projects. McMoRan ended 2002 with positive working capital and $14.3 million of unrestricted cash. While McMoRan's current cash flows continue to be sensitive to market, operational and financial risks, management believes current oil and gas market conditions and projected production levels from McMoRan's existing producing properties, among other factors, will enable McMoRan to continue to fund its operations and meet its obligations during 2003.

Over the longer-term McMoRan must develop financial resources and secure financing for its operations through the discovery, development and production of oil and gas reserves, the identification and exploitation of new business opportunities involving its Main Pass alliance with K1 or otherwise. McMoRan believes recent successful oil and gas exploration results, together with the significant exploration potential for its remaining acreage position and its opportunities to participate in new business development in the energy industry through its affiliation with K1, including the Main Pass alliance, position the company to enable it to achieve these goals. During 2003 McMoRan will continue to pursue additional arrangements with other industry participants to drill prospects management has identified on its significant acreage position, and will be actively involved with K1 in assessing potential additional business opportunities. The ultimate outcome of these efforts is subject to various uncertainties, many of which are beyond McMoRan's control, including oil and gas prices, oil and gas production rates, exploration results and reliance on third parties to conduct exploration and development activities on our current prospects, among other factors. While McMoRan cannot ensure the ultimate success of these efforts, management believes that the resolution of the significant uncertainties McMoRan faced at the beginning of 2002, together with the current activities described above, provide significant opportunities to achieve the company's overall business objectives.

4. 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 (Note 3). Each $25 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. McMoRan paid $0.9 million of preferred dividends during 2002. 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.

5. EXPLORATION ACREAGE

Effective January 1, 2000, McMoRan acquired from Texaco Exploration and Production Inc. (Texaco), now a subsidiary of ChevronTexaco Corp., the right to explore and earn assignments of operating rights in 89 unexplored oil and gas properties. The properties covered about 391,000 gross acres and are located in water depths ranging from 10 to 2,600 feet in federal and state waters offshore Louisiana and Texas. McMoRan has met all of its requirements to incur or commit to incur a minimum of $110 million of exploration expenditures on these properties by June 30, 2003 (Note 11).

On January 14, 2000, McMoRan purchased from Shell Offshore Inc. (Shell), a wholly owned subsidiary of Royal Dutch Petroleum Co., Shell's interest in 55 exploration leases for $37.8 million after transaction costs and purchase adjustments. The leases covered approximately 260,000 gross acres and are located in varying water depths of up to a maximum of approximately 2,000 feet in the offshore Louisiana area. McMoRan funded the purchase with borrowings under its then existing revolving bank credit facilities (Note 10).

Unless extended, McMoRan's offshore exploration agreement with Texaco will expire on January 1, 2004, at which time its right to continue to identify prospects and drill to earn leasehold interests not previously earned will expire, except for those prospects as to which it has committed to drill an exploration well. Further, approximately 30% of the approximate 160,000 gross acres subject to McMoRan's agreement with Texaco have lease expiration dates prior to January 1, 2004. Also, approximately 40% of McMoRan's undeveloped acres have lease expiration dates prior to January 1, 2004. Finally, of the approximate 100,000 gross acres attributable to its potential reversionary interests, approximately 15% have lease expiration dates prior to January 1, 2004. None of the leases relating 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. McMoRan can retain its exploration rights to the above referenced acreage by either conducting successful exploration activities on the leases or otherwise negotiating an extension of their term with Texaco and others.

6. 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 $2.2 million in 2002, $10.6 million in 2001 and $12.1 million in 2000. 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 during 2002 reflect the corresponding reduction in services provided to McMoRan following certain substantial sales transactions (Notes 2 and 3), as well as the effect of the Co-Chairmen of McMoRan's Board of Directors agreeing not to receive any cash compensation during 2002 (Note 8). At December 31, 2002, McMoRan had an obligation to fund $3.2 million of FM Services benefit costs primarily reflecting employee pension and postretirement medical obligations (Notes 7 and 8).

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

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

	December 31, 2002	December 31, 2001
Oil and gas property, plant and equipment (Note 12)	$ 184,848	$ 233,103
Other	-	585
	184,848	233,688
Accumulated depreciation	(146,953)	(135,169)
Property, plant and equipment, net	$ 37,895	$ 98,519

The components of other assets follow (in thousands):

	December 31, 2002	December 31, 2001
Long-term receivable [a]	$ -	$ 7,486
Restricted cash (Note 11)	3,500	3,500
Deferred financing fees	-	495
Discontinued operations receivables	470	-
Other	-	250
	$ 3,970	$ 11,731

a. Represents a third party contractual obligation to reimburse Freeport Sulphur for 50 percent of reclamation costs it incurred associated with the Caminada sulphur mine and facilities. This contractual right was assigned to OSFI as consideration for certain reclamation related services rendered (Note 2).

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

	December 31, 2002	December 31, 2001
Retiree medical liability (Note 8)	$ 4,567	$ 3,881
Accrued workers compensation and group insurance	3,131	3,523
Sulphur-related environmental liability (Note 11)	3,500	3,500
Defined benefit pension plan liability (Note 8)	1,964	1,885
Nonqualified pension plan liability	549	542
Deferred revenues, compensation and other	1,174	1,420
Liability for management services (Note 6)	3,233	-
Discontinued operations liabilities	736	-
	$ 18,854	$ 14,751

8. EMPLOYEE BENEFITS

Stock-Based Awards. In May 2001, the McMoRan shareholders approved the McMoRan 2001 Stock Incentive Plan (the 2001 Plan). The 2001 Plan is authorized to grant stock options, stock appreciation rights and restricted stock units (collectively 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. Options to purchase 263,500 McMoRan common shares were available for grant as of December 31, 2002, including options representing 106,250 shares under the 2001 Plan, 36,125 shares under the 2000 Plan, 70,125 shares under the 1998 Plan, and 51,000 shares under the Director Plan.

In 2002, McMoRan granted restricted stock units that will be converted ratably into 50,000 shares of McMoRan common stock on the grant anniversary date over the next three years. All of the restricted stock units were outstanding at December 31, 2002. At December 31, 2002, McMoRan did not have any stock appreciation rights outstanding. A summary of stock options outstanding follows:

	2002		2001		2000	
	Number of Options	Average Option Price	Number of Options	Average Option Price	Number of Options	Average Option Price
Beginning of year	2,448,402	$17.07	1,901,952	$17.42	1,891,113	$17.06
Granted	1,188,250	9.90	648,000	16.06	165,750	19.16
Exercised	-	-	(3,724)	13.21	(73,239)	13.05
Expired/forfeited	(243,441)	13.54	(97,826)	17.33	(81,672)	16.54
End of year	3,393,211	14.81	2,448,402	17.07	1,901,952	17.42

Summary information of all stock options outstanding at December 31, 2002 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	9.4 years	$3.97	-	$ -
$6.17	520,125	9.1 years	6.17	9,375	6.17
$10.56 to $15.78	1,171,362	5.2 years	13.38	1,092,111	13.34
$16.28 to $22.14	1,615,024	5.6 years	18.50	1,126,897	19.06
$25.31	54,700	5.2 years	25.31	54,700	25.31
	3,393,211			2,283,083	

In connection with McMoRan's efforts to reduce its 2002 administrative and overhead expenses, 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. On January 28, 2002, a total of 575,000 immediately exercisable stock options were granted in this regard having a term of ten years and an exercise price of $14.00 per share.

Pension Plans and Other Benefits. Prior to the Merger, McMoRan's defined benefit plan assets and liabilities and related costs were immaterial because of McMoRan's limited number of employees. In connection with the Merger, McMoRan merged its plan with Freeport Sulphur's defined benefit pension plan. During 2000, McMoRan decided 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 and 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, 2002, this shortfall approximated $2.0 million. McMoRan will also have to fund a portion of pension obligations associated with FM Services' employees (Notes 6 and 7), which at December 31, 2002 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 its remaining sulphur employees, following the sale of the assets comprising its recovered sulphur business (Note 2). McMoRan also recorded approximately $0.2 million in special termination benefits associated with certain of these employees. In addition, McMoRan 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). Information on the McMoRan plans follows (dollars in thousands):

	Pension Benefits		Other Benefits	
	2002	2001	2002	2001
Change in benefit obligation:				
Benefit obligation at the beginning of year	$ (11,543)	$ (12,309)	$ (5,981)	$ (4,602)
Service cost	-	-	(37)	(62)
Interest cost	(581)	(433)	(505)	(335)
Plan amendments	-	244	-	-
Curtailment loss	-	-	(397)	-
Special termination benefits	-	-	(164)	-
Actuarial losses	-	-	(1,361)	(1,429)
Participant contributions	-	-	(205)	(109)
Benefits paid	625	955	800	556
Benefit obligation at end of year	(11,499)	(11,543)	(7,850)	(5,981)
Change in plan assets:				
Fair value of plan assets at beginning of year	9,658	10,327	-	-
Actual return on plan assets	502	286	-	-
Employer/participant contributions	-	-	800	556
Benefits paid	(625)	(955)	(800)	(556)
Fair value of plan assets at end of year	9,535	9,658	-	-
Funded status	(1,964)	(1,885)	(7,850)	(5,981)
Unrecognized net actuarial gain	-	-	3,278	2,089
Unrecognized prior service cost	-	-	5	11
Accrued benefit cost	$ (1,964)	$ (1,885)	$ (4,567)	$ (3,881)
Weighted-average assumptions (percent):				
Discount rate	n/a	n/a	6.75	7.25
Expected return on plan assets	n/a	n/a	-	-
Rate of compensation increase	n/a	n/a	-	-

The initial health care cost trend rate used for the Other Benefits was 11 percent in 2002, 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. The components of net periodic benefit cost for McMoRan's plans follow (in thousands):

	Pension Benefits			Other Benefits		
	2002	2001	2000	2002	2001	2000
Service cost	$ -	$ -	$ 329	$ 37	$ 62	$ 87
Interest cost	581	433	879	505	335	189
Curtailment loss	-	-	1,300	397	-	1,540
Special termination benefits	-	-	-	164	-	158
Expected return on plan assets	(502)	(286)	(1,124)	-	-	-
Amortization of prior service costs	-	-	-	1	1	5
Recognition of net actuarial loss	-	-	-	177	7	-
Net periodic benefit cost	$ 79	$ 147	$ 1,384	$ 1,281	$ 405	$ 1,979

McMoRan has an employee savings plan under Section 401(k) of the Internal Revenue Code. The plan allows eligible employees to contribute up to 20 percent of their pre-tax compensation, subject to a limit prescribed by the Internal Revenue Code, which was $10,500 for both 2000 and 2001 and $11,000 for 2002. McMoRan matches 100 percent of the first 5 percent of the employees' contribution, with such matching amounts vesting after three years of service. 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 $0.4 million in 2002, $0.6 million in 2001 and $0.8 million in 2000 to its results of operations for the Section 401(k) savings plan and the new 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.

9. INCOME TAXES

McMoRan accounts for income taxes pursuant to SFAS 109, "Accounting for Income Taxes." In 1998, McMoRan recorded a $35.0 million net deferred tax asset upon the acquisition of Freeport Sulphur's assets. As a result of McMoRan's decision to exit active participation in its sulphur business and after evaluating projected results from operations, during 2000 McMoRan concluded that a full valuation allowance was required for its net deferred tax asset resulting in a charge to income tax expense of $34.9 million (Note 2). McMoRan has $176.6 million of net deferred tax assets as of December 31, 2002, resulting from net operating loss carryfowards and other temporary differences related to McMoRan's activities. McMoRan has provided a valuation allowance, including approximately $25 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, 2002 and 2001 follow (in thousands):

	December 31,	
	2002	2001
Net operating loss carryforwards (expire 2006-2020)	$ 121,601	$ 85,434
Property, plant and equipment	22,518	56,725
Reclamation and shutdown reserves	16,289	27,124
Deferred compensation, postretirement and pension benefits and accrued liabilities	10,672	11,631
Other	5,528	6,895
Less valuation allowance	(176,608)	(187,809)
Net deferred tax asset	$ -	$ -

McMoRan recognized no income tax provision or benefit prior to 1999. McMoRan's income tax provision, consisting entirely of state income taxes, totaled $7,000 during 2002 and $8,000 during 2001.

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

	2002		2001		2000	
	Amount	Percent	Amount	Percent	Amount	Percent
Income tax (expense) benefit computed at the federal statutory income tax rate	$ (6,314)	35%	$ 51,821	35%	$ 33,798	35%
Change in valuation allowance	11,201	(62)	(48,551)	(33)	(68,740)	(71)
State taxes and other	(4,894)	27	(3,278)	(2)	-	-
Income tax provision	$ (7)	- %	$ (8)	- %	$ (34,942)	(36)%

10. CREDIT FACILITIES

	December 31,	
	2002	2001
	(In Thousands)	
Freeport Sulphur credit facility, average rate 6.7% in 2002 and 7.4% in 2001	$ -	$ 55,000
MOXY credit facility, average rate 2.6% in 2002 and 3.6% in 2001	-	49,657
Less: current portion	-	(57,000)
Long-term borrowing on oil and gas credit facility	$ -	$ 47,657

As part of a previous strategic alliance with Halliburton Company (Halliburton), Halliburton provided a guarantee that initially provided up to $50 million of borrowings available to MOXY under its 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 North Tern Deep 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 3).

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. At December 31, 2001, McMoRan's borrowings outstanding under this portion of the oil and gas credit facility totaled $2.0 million. All borrowings ($2.0 million) under this portion of the facility were classified as a current liability at December 31, 2001. Borrowings outstanding under this portion of the facility at the time it was terminated ($4.0 million) were repaid in February 2002.

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 2) and a portion of the proceeds generated by a public equity offering (Notes 3 and 4). The sulphur credit facility was then terminated.

In July 2002, MOXY entered into a one-year, $10 million revolving bank credit facility with Hibernia National Bank. Amounts available for borrowing under this facility are subject to an oil and gas reserve borrowing base, which provided MOXY up to $4.5 million borrowing capacity under the facility. The amount available for borrowing under the facility decreases by $0.5 million per month. The amount available for borrowing at December 31, 2002 was $2.0 million. The variable rate loan is secured by all of MOXY's oil and gas producing properties and is guaranteed by McMoRan. MOXY has made no borrowings under this credit facility.

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 5). As of December 31, 2002, McMoRan has met this commitment by expending or having others expend a total of $112.0 million under the terms of the agreement. Exploration of the acreage rights obtained from Texaco will continue at least through December 31, 2003 (Note 5).

Previously, McMoRan had a contract with CLK Company LLC (CLK), an independently owned company, to provide geological and geophysical services to McMoRan on an exclusive basis. The contract had 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 3 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 $2.2 million in 2002, $3.4 million in 2001 and $3.1 million in 2000. 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, with total annual payments through 2007 aggregating $0.7 million (see below).

Long-term Contracts and Operating Leases. As discussed in Note 2, McMoRan sold its sulphur transportation and terminaling assets to a newly formed 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 involve the leasing of sulphur rail cars previously used in its recovered sulphur business and certain office space (see "Commitments" above). McMoRan's total minimum annual contractual charges aggregate $6.7 million, with $1.3 million in 2003, $0.9 million in both 2004 and 2005, $0.7 million in 2006, $0.6 million in 2007 and $2.3 million thereafter.

McMoRan currently has a sublease arrangement with IMC Global for all the rail cars under lease through 2003. McMoRan is receiving a sufficient amount of sublease income to offset the lease expense under the rail car leases. McMoRan is currently in discussions regarding an extension of this sublease arrangement or assignment of the sulphur rail car leases. The final McMoRan sulphur rail car lease expires in March 2011.

Other Liabilities. Freeport Sulphur has an obligation to IMC Global for a portion of IMC Global 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 year-end 2001 estimate of the 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 to $22.4 million. The liability totaled $23.0 million at December 31, 2002, 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 its 1995 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 "Other assets" in the accompanying balance sheets.

Environmental. 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 2 for disclosure about McMoRan's progress towards resolving 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, 2002, McMoRan has neither identified nor recorded any amounts associated with its agreement to assume certain historical oil and gas liabilities from IMC Global (Note 2).

Other. 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.

12. 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,	
	2002	2001
	(In Thousands)	
Unevaluated properties, including drilling in progress	$ 9,387	$ 5,321
Evaluated	175,461	227,782
Subtotal	184,848	233,103
Less accumulated depreciation and amortization	(146,953)	(135,078)
Net oil and gas properties	$ 37,895	$ 98,025

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

	Years Ended December 31,		
	2002	2001	2000
		(In Thousands)	
Acquisition of properties:			
Proved	$ -	$ 4,322	$ -
Unproved	-	859	45,838
Exploration costs	7,642	35,475	68,636
Development costs	3,788	45,983	12,910
	$ 11,430	$ 86,639	$ 127,384

Proved Oil and Gas Reserves (Unaudited). Proved oil and gas reserves at December 31, 2002 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. 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 is in millions of cubic feet (MMcf).

	Oil			Gas		
	2002	2001	2000	2002	2001	2000
Proved reserves:						
Beginning of year	6,373	5,507	5,245	48,317	56,842	62,575
Revisions of previous estimates	(19)	1,360	789	(2,060)	(4,406)	(3,782)
Discoveries and extensions	-	54	1,388	-	7,018	35,468
Production	(1,153)	(1,417)	(1,152)	(5,851)	(11,137)	(8,291)
Sale of reserves	(4,622)	-	(763)	(26,423)	-	(29,128)
Purchase of reserves	-	869	-	-	-	-
End of year	579	6,373	5,507	13,983	48,317	56,842
Proved developed reserves:						
Beginning of year	6,099	4,843	4,499	35,872	35,584	61,630
End of year	412	6,099	4,843	8,822	35,872	35,584
Equity in proved reserves of unconsolidated affiliate [a]	1,939	-	-	-	-	-

a. Represents McMoRan's 33.3 percent interest in the K-Mc I Joint Venture, which owns the oil operations at Main Pass.

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 prescribed by the SEC. These regulations require the use of year-end oil and gas prices in the projection of future net cash flows. Future income taxes were determined using applicable tax rates and future tax deductions, discounted to present value on a year-by-year basis.

	December 31,	
	2002	2001
	(In Thousands)	
Future cash inflows	$ 89,663	$ 244,193
Future costs applicable to future cash flows:		
Production costs	(23,356)	(115,031)
Development and abandonment costs	(15,747)	(53,578)
Future net cash flows before income taxes	50,560	75,584
Future income taxes	-	-
Future net cash flows	50,560	75,584
Discount for estimated timing of net cash flows (10% discount rate)	(10,073)	(6,950)
	$ 40,487	$ 68,634
Equity in unconsolidated affiliates' discounted future net cash flows[a]	$ 7,371	$ -

a. Represents McMoRan's 33.3 percent interest in the K-Mc I Joint Venture, which owns the oil operations at Main Pass. The future cash flows from Main Pass will be used by K-Mc I primarily to repay the joint venture's debt and satisfy the reclamation costs ultimately incurred for the field.

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

	Years Ended December 31,		
	2002	2001	2000
	(In Thousands)		
Beginning of year	$ 68,634	$ 368,991	$ 115,121
Revisions:			
Changes in prices	26,925	(343,526)	108,313
Accretion of discount	6,863	42,947	11,512
Change in reserve quantities	(5,735)	(54,209)	(5,832)
Other changes, including revised estimates of development costs and rates of production	(9,066)	(11,114)	3,183
Discoveries and extensions, less related costs	-	13,146	264,320
Development costs incurred during the year	3,512	28,231	9,056
Change in future income taxes	-	60,477	(60,477)
Revenues, less production costs	(17,545)	(37,926)	(33,837)
Sale of reserves in place	(33,101)	-	(42,368)
Purchase of reserves in place	-	1,617	-
End of year	$ 40,487	$ 68,634	$ 368,991

13. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	Revenues	Operating Income (Loss)	Net Income (Loss)	Net Income (Loss) per Share Basic	Net Income (Loss) per Share Diluted
	(In Thousands, Except Per Share Amounts)				
2002					
1st Quarter	$ 13,586	$ 24,536[a]	$ 24,039	$ 1.51	$ 1.51
2nd Quarter	11,400	(1,163)	(2,522)[b]	(0.16)	(0.16)
3rd Quarter	9,785	(12,573)	(10,256)[c]	(0.64)	(0.64)
4th Quarter	8,997	7,142[d]	5,780[d]	0.36	0.27
	$ 43,768	$ 17,942	$ 17,041	1.06	0.91
2001					
1st Quarter	$ 15,798	$ (36,019)[e]	$ (44,788)[f]	$ (2.83)	$ (2.83)
2nd Quarter	16,093	(14,260)	(19,017)[g]	(1.20)	(1.20)
3rd Quarter	24,555	(5,700)	(8,366)	(0.53)	(0.53)
4th Quarter	16,496	(48,938)[h]	(75,890)[i]	(4.78)	(4.78)
	$ 72,942	$ (104,917)	$ (148,061)	(9.33)	(9.33)

a. Includes $29.2 million gain on the sale of three oil and gas properties in February 2002 (Note 3).
b. 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 2).
c. 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 2).
d. Includes $14.1 million gain from the sale of the oil producing assets at Main Pass to the K-Mc I Joint Venture (Note 2). The gain was partially offset by a $4.4 million impairment charge (Note 1).
e. Includes $31.1 million of non-productive exploratory well costs associated with the West Delta Block 12 No. 1 and Garden Banks Block 272 No. 1 wells.
f. Includes a $5.4 million charge to reduce Freeport Sulphur's inventory to its then estimated net realizable value.
g. Includes a $4.6 million charge to reduce Freeport Sulphur's inventory to it then estimated net realizable value.
h. Includes oil and gas-related impairment charges totaling $39.1 million (Note 1).
i. Includes a $10.8 million charge to reduce the sulphur business assets to their estimated net fair value at December 31, 2001 (Note 2).

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 years ended December 31, 2001 and December 31, 2000, 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 two fiscal years 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 two fiscal years ended December 31, 2001 and December 31, 2000, 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.

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 2003 Annual Meeting to be held on May 1, 2003 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 2003 Annual Meeting to be held on May 1, 2003 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" and "Proposal to Adopt the 2003 Stock Incentive Plan – Equity Compensation Plan Information" of the Proxy Statement submitted to the stockholders of the registrant in connection with its 2003 Annual Meeting to be held on May 1, 2003 is incorporated by reference.

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 2003 Annual Meeting to be held on May 1, 2003 is incorporated by reference.

Item 14. 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 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.

(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 and as of March 26, 2003 the registrant filed five Current Reports on Form 8-K. The registrant filed four reports reporting events under Item 5. dated November 18, 2002, December 17, 2002, February 26, 2003 and March 13, 2003 and a Current Report on Form 8-K reporting an event under Item 9. dated January 22, 2003.

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, 2002 and for the year then ended and have issued our report thereon dated January 22, 2003. Our audit also included the accompanying schedule of valuation and qualifying accounts (financial statement schedule) for the year ended December 31, 2002. This schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audit. The Company's consolidated financial statements and related schedules of valuation and qualifying accounts for the years ended December 31, 2001 and 2000 were audited by other auditors who have ceased operations and whose report with respect to the schedules dated April 16, 2002 indicated that such schedules for 2001 and 2000 fairly state, 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 2002 financial statement schedule referred to above, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly in all material respects the information set forth therein.

Ernst & Young LLP

New Orleans, Louisiana
January 22, 2003

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, 2002.

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.

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:					
2002					
Sulphur	$ 63,876	$ -	$ -	$ (25,329)[a]	$ 38,547
Oil	18,676	668	-	(11,350)[b]	7,994
	$ 82,552	$ 688	$ -	$ (36,699)	$ 46,541
2001					
Sulphur	$ 69,187	$ -	$ -	$ (5,311)[c]	$ 63,876
Oil [d]	15,980	3,466	-	(770)	18,676
	$ 85,167	$ 3,466	$ -	$ (6,081)	$ 82,552
2000					
Sulphur [e]	$ 47,988	$ 40,887	$ -	$ (19,688)	$ 69,187
Oil [f]	10,976	682	-	4,322[f]	15,980
	$ 58,964	$ 41,569	$ -	$ (15,366)	$ 85,167

a. Reflects the completion of the reclamation activities at the Caminda 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.

b. 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.

c. 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.

d. 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).

e. Reflects the decision to cease production from the Main Pass sulphur mine. Reclamation costs associated with the Main Pass sulphur mine and related facilities were accrued. Costs incurred reflect the commencement of reclamation activities at the Main Pass sulphur mine ($13.7 million) and related facilities ($2.0 million) and the final reclamation activities at the Culberson sulphur mine in West Texas ($3.4 million), and costs for the Caminda and Grand Ecaille sulphur mines.

f. Includes the liabilities assumed in connection with the acquisition of the Eugene Island Blocks 193/208/215 field ($3.9 million), the Eugene Island Block 108 field ($1.9 million) and $0.2 million associated with properties acquired from Shell. These assumed liabilities were partially offset by a decrease of $1.7 million in the assumed liability at Vermilion Block 144.

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 26, 2003.

McMoRan Exploration Co.

By: /s/ Richard C. Adkerson
Richard C. Adkerson
Co-Chairman of the Board, 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 26, 2003.

* James R. Moffett	Co-Chairman of the Board
/s/ Richard C. Adkerson Richard C. Adkerson	Co-Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)
* B. M. Rankin, Jr.	Vice Chairman of the Board
* C. Howard Murrish	Vice Chairman of the Board and Executive Vice President
* Glenn A. Kleinert	Executive Vice President and Director
/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)
* Morrison C. Bethea	Director
* Robert A. Day	Director
* Gerald J. Ford	Director
* H. Devon Graham, Jr.	Director
* Gabrielle K. McDonald	Director
* J. Taylor Wharton	Director

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

CERTIFICATIONS

I, Richard C. Adkerson, certify that:

1. I have reviewed this annual report on Form 10-K of McMoRan Exploration Co.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

    a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

    b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

    c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

    a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 26, 2003

/s/ Richard C. Adkerson
Richard C. Adkerson
Co-Chairman of the Board, President
and Chief Executive Officer

CERTIFICATIONS

I, Nancy D. Parmelee, certify that:

1. I have reviewed this annual report on Form 10-K of McMoRan Exploration Co.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   c) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   d) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 26, 2003

/s/ Nancy D. Parmelee
Nancy D. Parmelee
Senior Vice President,
Chief Financial Officer and Secretary

McMoRan Exploration Co.
Exhibit Index

<u>Exhibit Number</u>

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	By-laws of McMoRan as amended effective February 1, 1999. (Incorporated by reference to Exhibit 3.2 to the McMoRan 1998 Form 10-K).
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.
4.8	Registration Rights Agreement dated December 16, 2002 between McMoRan Exploration Co. and K1 USA Energy Production Corporation.
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 Global Inc., IMC Global Phosphate Company, Phosphate Resource Partners Limited Partnership, IMC Global Phosphates MP Inc., McMoRan Oil & Gas and McMoRan. (Incorporated by reference to Exhibit 10.10 to McMoRan's Second Quarter 2002 Form 10-Q).
10.3	Services Agreement dated as of November 17, 1998 between McMoRan and FM Services Company. (Incorporated by reference to Exhibit 10.11 to McMoRan 1998 Form 10-K).
10.4	Offshore Exploration Agreement dated December 20, 1999 between Texaco Exploration and Production Inc. and McMoRan Oil & Gas. (Incorporated by reference to Exhibit 10.34 in the McMoRan 1999 Form 10-K).

10.5	Participation Agreement dated as of June 15, 2000 but effective as of March 24, 2000 between McMoRan Oil & Gas and Halliburton Energy Services, Inc. (Incorporated by reference to Exhibit 10.34 to McMoRan's Second-Quarter 2000 Form 10-Q).
10.6	Termination Agreement dated January 25, 2002 between Halliburton Company, Halliburton Energy Services Inc. and McMoRan Oil & Gas. (Incorporated by reference to Exhibit 10.15 to McMoRan's Second Quarter 2002 Form 10-Q).
10.7	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).
10.8	Exploration Agreement dated November 14, 2000 between McMoRan Oil & Gas LLC and Samedan Oil Corporation. (Incorporated by reference to Exhibit 10.17 to McMoRan's 2000 Form 10-K).
10.9	Credit Agreement dated as of July 1, 2002 among McMoRan Oil & Gas, as borrower, Hibernia National Bank, as agent, and the Lenders signatory thereto. (Incorporated by reference to Exhibit 10.18 to McMoRan's Second Quarter 2002 Form 10-Q).
10.10	Agreement for Purchase and Sale dated as of August 1, 1997 between FM Properties Operating Co. and McMoRan Oil & Gas (Incorporated by reference to Exhibit 10.27 to McMoRan's 2001 Form 10-K).
10.11	Asset Purchase Agreement dated effective December 1, 1999 between SOI Finance Inc., Shell Offshore Inc. and McMoRan Oil & Gas. (Incorporated by reference to Exhibit 10.33 in the McMoRan 1999 Form 10-K).
10.12	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).
10.13	Purchase and Sales agreement dated January 25, 2002 but effective January 1, 2002 by and between McMoRan Oil & Gas 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.)
10.14	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.)
10.15	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.)
10.16	Purchase and Sale Agreement dated May 9, 2002 by and between McMoRan Oil & Gas and El Paso Production Company. (Incorporated by reference to Exhibit 10.28 to McMoRan's Second Quarter 2002 Form 10-Q).
10.17	Amendment to Purchase and Sale Agreement dated May 22, 2002 by and between McMoRan Oil & Gas and El Paso Production Company. (Incorporated by reference to Exhibit 10.29 to McMoRan's Second Quarter 2002 Form 10-Q).
10.18	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.

10.19	Amended and Restated Limited Liability Company Agreement of K-Mc Venture LLC, a Delaware Limited Liability Company, dated December 16, 2002.
	Executive and Director Compensation Plans and Arrangements (Exhibits 20 through 30).
10.20	McMoRan Adjusted Stock Award Plan. (Incorporated by reference to Exhibit 10.1 of the McMoRan S-4).
10.21	McMoRan 1998 Stock Option Plan. (Incorporated by reference to Annex D to the McMoRan S-4).
10.22	McMoRan 2000 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.5 to McMoRan's Second-Quarter 2000 Form 10-Q).
10.23	McMoRan 1998 Stock Option Plan for Non-Employee Directors. (Incorporated by reference to Exhibit 10.2 of the McMoRan S-4).
10.24	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).
10.25	McMoRan Financial Counseling and Tax Return Preparation and Certification Program, effective September 30, 1998. (Incorporated by reference to Exhibit 10.13 to McMoRan's 1998 Form 10-K).
10.26	McMoRan 2001 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.36 to McMoRan's Second-Quarter 2001 Form 10-Q).
10.27	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).
10.28	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).
10.29	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).
10.30	Supplemental Agreement between FM Service 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).
12.1	Computation of Ratio of Earnings to Fixed Charges
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.

BOARD OF DIRECTORS

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

Richard C. Adkerson, 1994
Co-Chairman of the Board,
President and Chief Executive Officer
McMoRan Exploration Co.

Morrison C. Bethea, 2000
Chief of Thoracic Surgery,
Tenet Memorial Medical Center
Cardiac, Thoracic and Vascular Surgeon
Clinical Professor of Surgery,
Tulane University Medical Center

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

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

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

Glenn A. Kleinert, 2001
Executive Vice President
McMoRan Exploration Co.

Gabrielle K. McDonald, 2000
Judge, Iran-United States Claims Tribunal
Special Counsel on Human Rights to the
Chairman of the Board
Freeport-McMoRan Copper & Gold Inc.

C. Howard Murrish, 2001
Vice Chairman of the Board and
Executive Vice President
McMoRan Exploration Co.

B. M. Rankin, Jr. (3), 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

Board Committees:
(1) Audit
(2) Corporate Personnel
(3) Nominating
† 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,
President and Chief Executive Officer

Operations:

Glenn A. Kleinert
President and Chief Operating Officer
Oil and Gas Activities

C. Howard Murrish
Executive Vice President
Exploration

David C. Landry
Vice President
Development

Administration and Finance:

W. Russell King
Senior Vice President
Federal Government Affairs

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

Kathleen L. Quirk
Senior Vice President and 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 and
Controller-Financial Reporting

Internal Auditors:

PricewaterhouseCoopers 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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