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McMoRan Exploration Co.

2006 ANNUAL REPORT AND FORM 10-K

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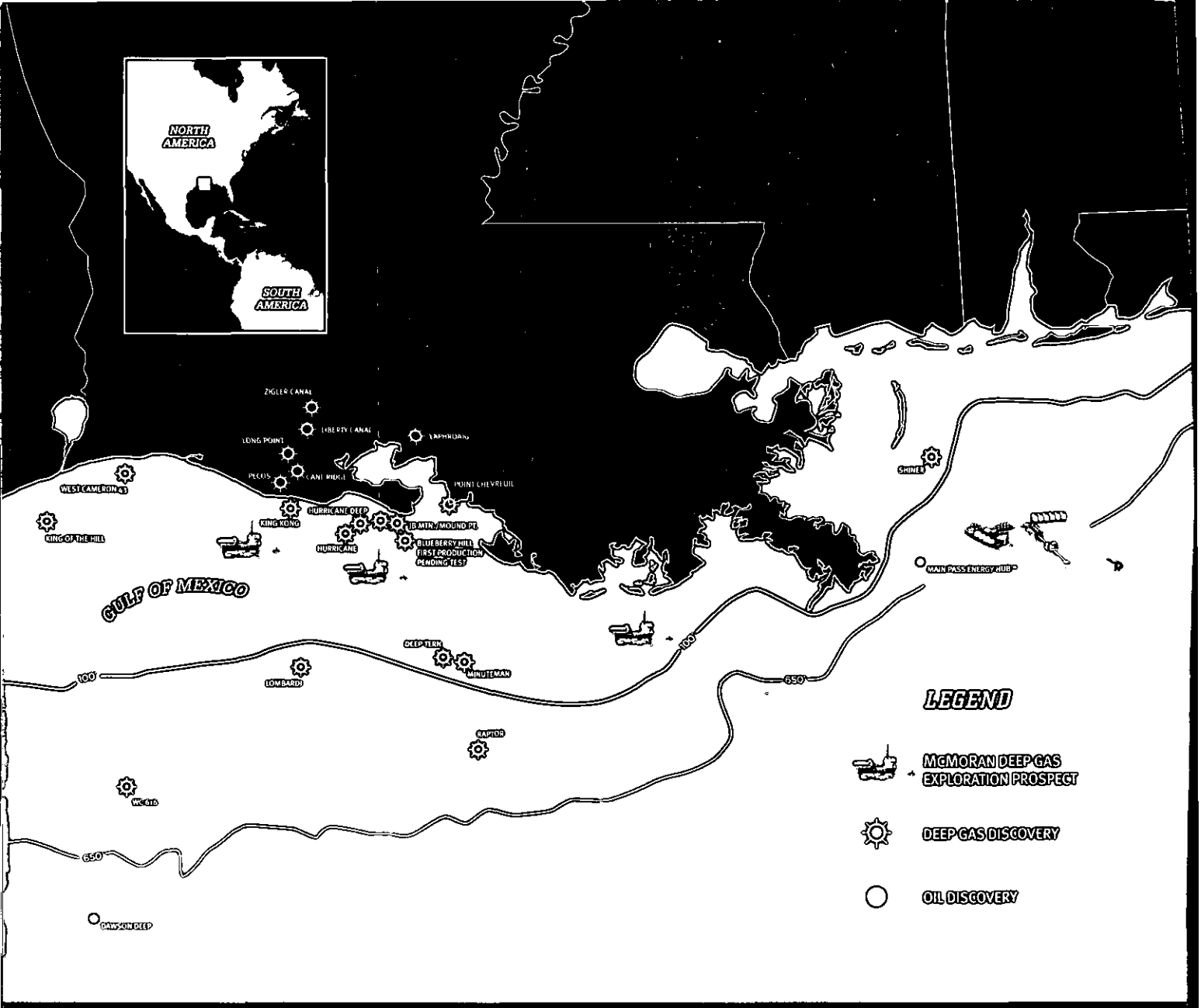


MOXY

The definition of "moxy" includes "expertise," "energy" and "dedication." Those same words define McMoRan Exploration Co. and activities in the Gulf Coast, including deep gas exploration and development of the Main Pass Energy Hub™.

exploration prospects in the shallow waters of the Gulf of Mexico and onshore South Louisiana. We also advanced our proposed Main Pass Energy Hub™ (MPEH™) liquefied natural gas (LNG) terminal by obtaining regulatory approval for the project from the U.S. Maritime Administration (MARAD).

To Our Shareholders:

During 2006, McMoRan Exploration Co. (NYSE: MMR) continued to pursue its focused strategy of targeting Deep Miocene exploration prospects in the shallow waters of the Gulf of Mexico and onshore South Louisiana. We also advanced our proposed Main Pass Energy Hub™ (MPEH™) liquefied natural gas (LNG) terminal by obtaining regulatory approval for the project from the U.S. Maritime Administration (MARAD). The theme of this year's annual report signifies the energy, determination and know-how that drive the opportunities and successes at McMoRan and the "MOXY" of our team.

Our continued pursuit over the last several years has proven that significant commercial hydrocarbons in the Deep Miocene trend exist below 15,000 feet. This success has allowed us to take a leadership role in the pursuit of deep gas. As a result, we have been successful in obtaining rights to held-by-production acreage through farm-ins and partnerships with several major oil and gas companies. We currently have rights to approximately 370,000 gross acres.

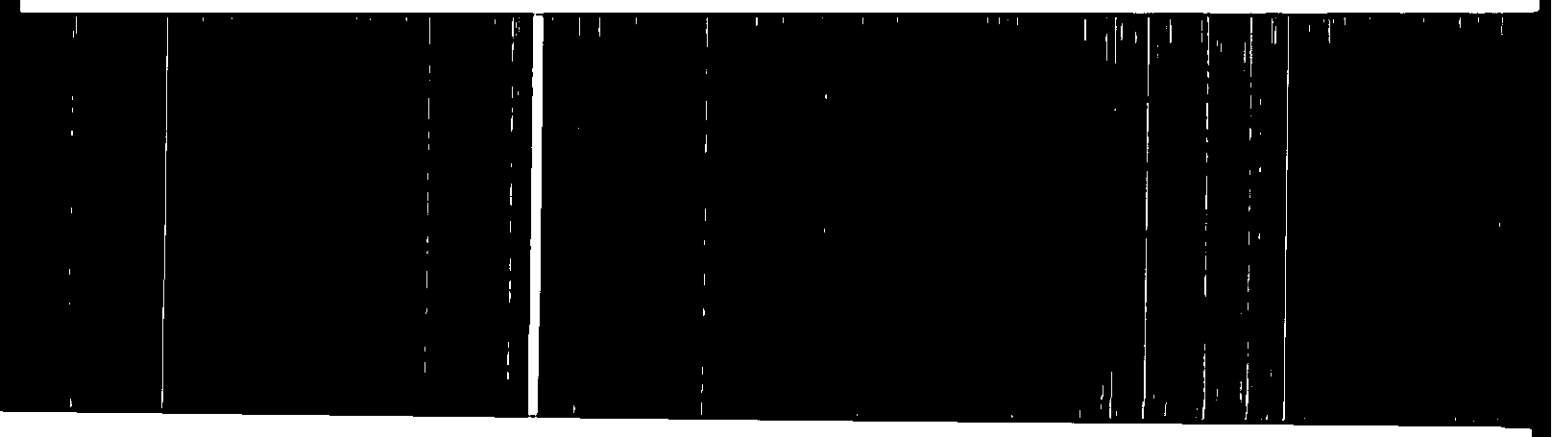
These relationships have afforded our exploration team access to highly attractive exploration targets and an exciting prospect inventory.

Our deep gas exploration efforts yielded five discoveries in 2006.

Since 2004, McMoRan has drilled 15 discoveries on 29 prospects. This success has allowed us to significantly increase our oil and gas production and reserves. During 2006, McMoRan's production increased 81 percent as we brought 14 new wells online. Our 2006 daily production averaged 65 million cubic feet of natural gas equivalents (MMcfe/d) compared to 36 MMcfe/d in 2005. Increased production rates combined with favorable prices for oil and natural gas resulted in oil and gas revenues of $196.7 million for 2006, which was 66 percent higher than revenues in 2005.

McMoRan produced a total of 23.9 billion cubic feet of natural gas equivalents (Bcfe) in 2006. Our reserve additions and revisions replaced 75 percent of production. Based on independent reservoir engineers' estimates, McMoRan's year end 2006 proved oil and gas reserves totaled 75.8 Bcfe.

In 2007, we will continue to expose shareholders to high risk/high reward exploration prospects in an effort to add major values to our current base. We plan to drill eight to 10 exploration wells that fit our "deeper pool" exploration model and our objectives of pursuing high impact targets.



EXPERTISE

With 35+ years of experience in the Gulf Coast region, McMoRan Exploration Co. has the expertise, skill and know-how to deliver.

In January 2007, MARAD issued a favorable Record of Decision on our MPEH™ license application. This approval is a significant development in our efforts to establish a new LNG gateway and natural gas delivery system for the U.S. with substantial onsite natural gas storage.

MPEH™ is the only LNG terminal project in the United States that combines regasification and on-site salt cavern storage with connections to premium U.S. natural gas markets. As approved, the facility will be capable of regasifying LNG at a peak rate of 1.6 Bcf per day, storing 28 Bcf of natural gas in salt caverns and delivering 3.1 Bcf per day, including gas from storage, of natural gas to the U.S. market.

Establishing commercial arrangements to pursue the highly attractive potential of the facility will be a major focus of our company in 2007.

We appreciate the "MOXY" of our team who are executing our business strategy, and we thank our Board of Directors for their leadership and counsel as we work toward success in 2007. We are positive about the potential of our deep gas exploration program and offshore LNG project. We look forward to reporting the results to you during 2007 as we work to create values that we believe are available in our focused exploration areas and from the development of our MPEH™ project.

WARMEST REGARDS,

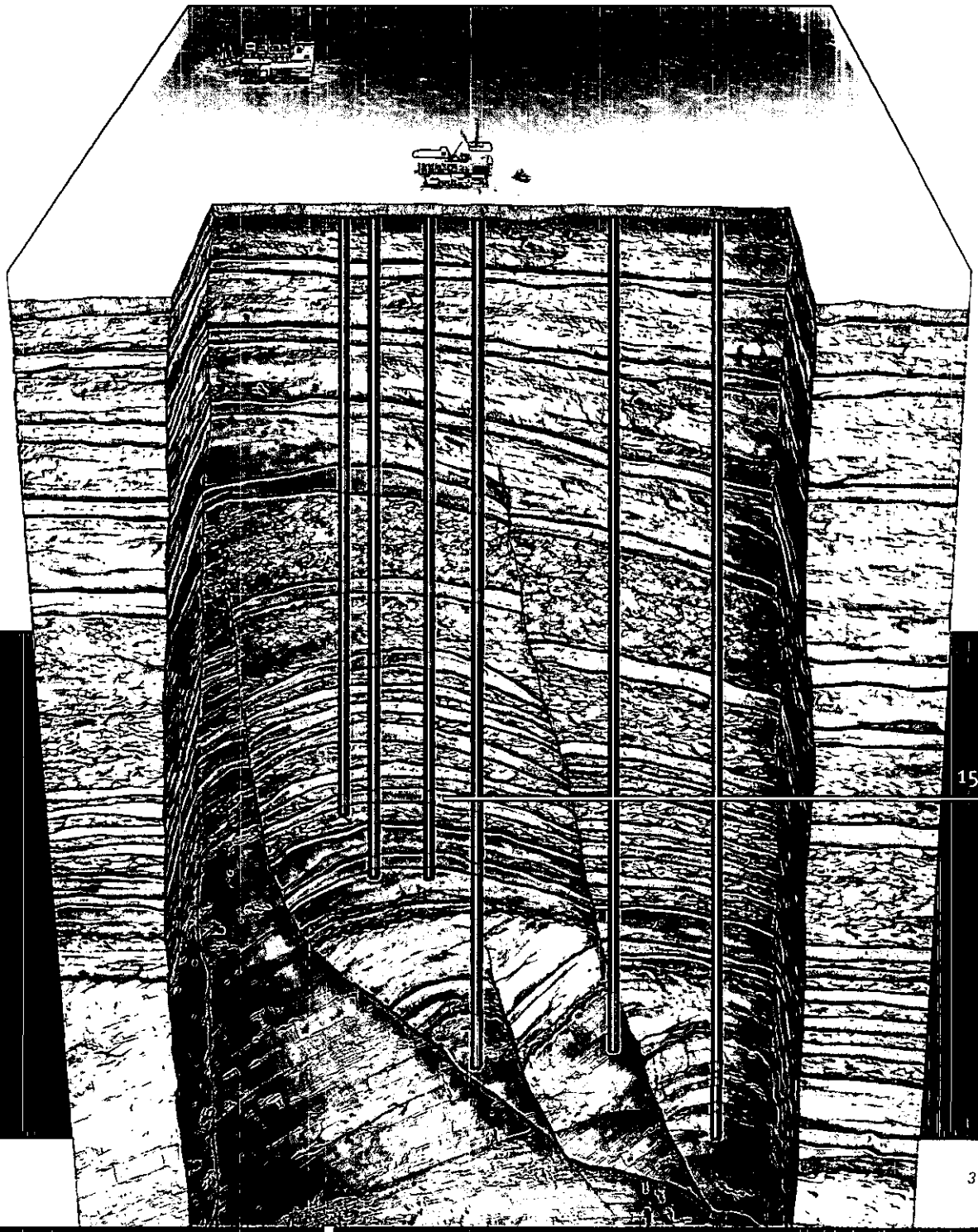
James R. Moffett
Co-Chairman of the Board

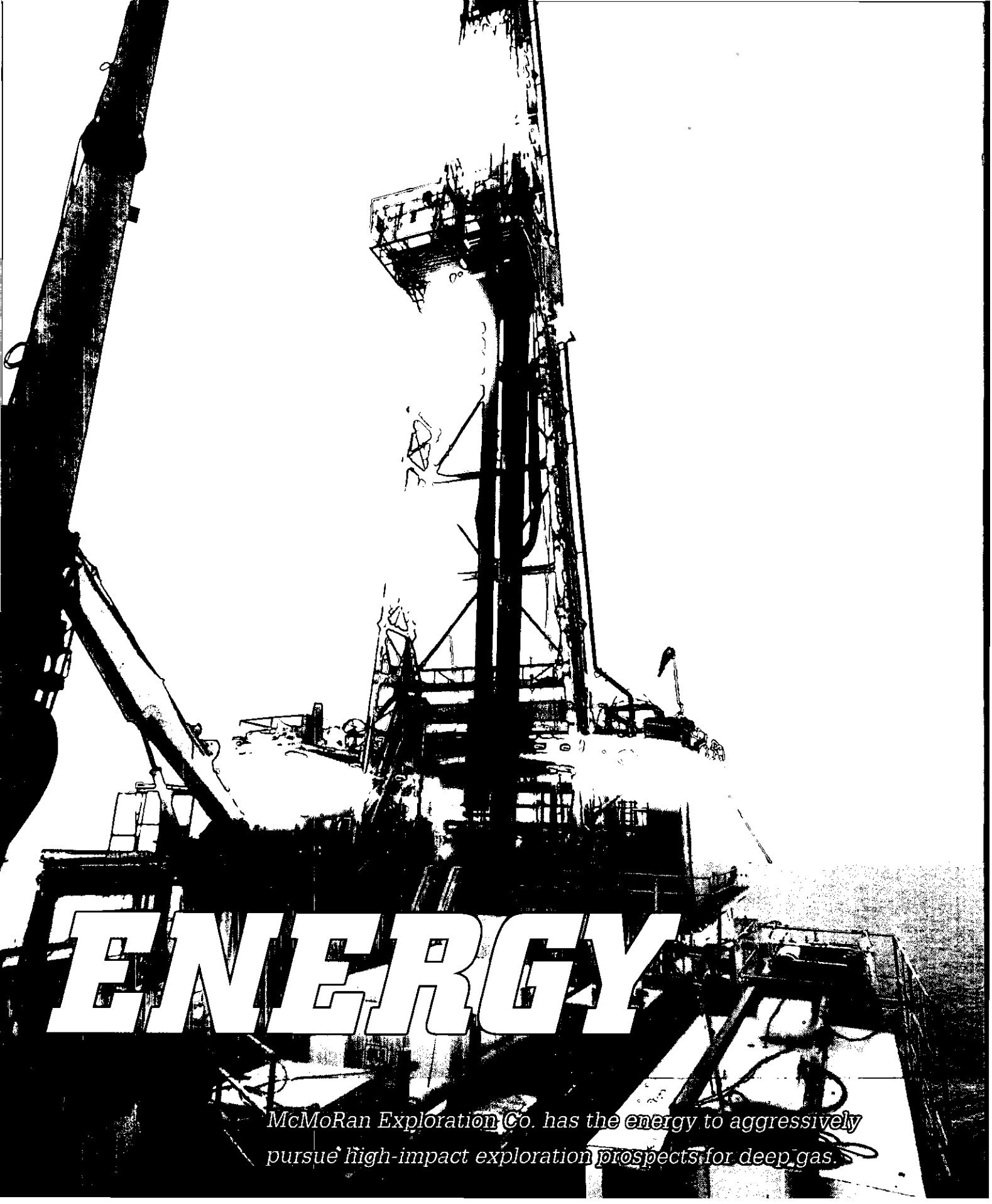
Richard C. Adkerson
Co-Chairman of the Board

Glenn A. Kleinert
President and Chief Executive Officer

March 16, 2007

activities and participate as an industry leader in exploring for "deeper pools" of hydrocarbons below existing or previous shallow production.





ENERGY

McMoRan Exploration Co. has the energy to aggressively pursue high-impact exploration prospects for deep gas.

WILDCATTING WITH MOXY

The Gulf of Mexico has been an important source of hydrocarbons that have helped fuel the U.S.'s energy demand for many decades.

Our unique approach involves drilling for energy resources that lie beneath existing or previous shallower production on the Gulf of Mexico shelf or onshore in Southern Louisiana in a strategy we refer to as the "deep gas" play. We drill much deeper than conventional wells — to depths of 15,000 to 25,000 feet — to locate older and deeper sediments containing pools of hydrocarbons in the Deep Miocene geological trend.

Our continued successes below 15,000 feet in the shallow waters and onshore and the success by other companies in the deepwater Gulf of Mexico illustrate the vitality of the Gulf of Mexico. Both plays, which were formed by similar depositional processes over time, are under-explored, thus creating opportunities for those that have knowledge in these areas and are willing to take the exploration risk.

Existing infrastructure allows shallow water discoveries to be brought online quickly and provide significant cost savings relative to deep water discoveries as infrastructure production is non existent in deepwater. This point is evidenced by our five discoveries in 2006:

- Pecos, located onshore Vermilion Parish, Louisiana, was drilled to a depth of 18,795 feet in April 2006. Production commenced in August 2006.
- King of the Hill, located at High Island Block 131 in 50 feet of water, was drilled to a depth of 16,290 feet in April 2006. Production commenced in August 2006.
- Liberty Canal, an onshore well in Vermilion Parish, Louisiana, was drilled to a depth of 16,594 feet in May 2006. Production commenced in October 2006.
- Zigler Canal, an onshore well in Vermilion Parish, Louisiana, was drilled to a depth of 13,635 feet in November 2006. Production commenced in December 2006.
- Point Chevreuil, located in less than 10 feet of water in the South Belle Isle Field offshore St. Mary Parish, Louisiana, was drilled to 17,011 feet in March 2006. Production commenced in December 2006.

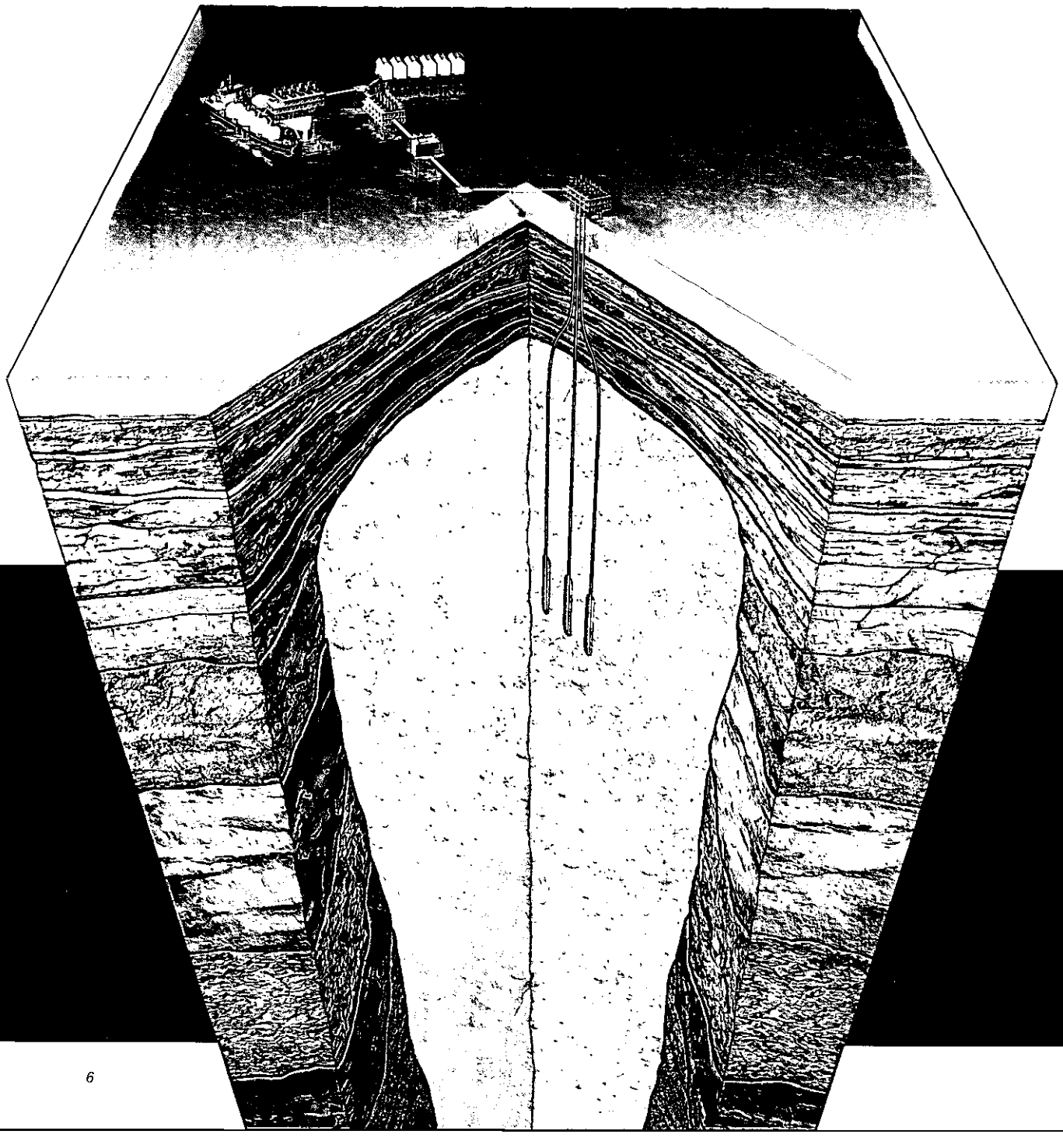
To date in 2007 we have positive drilling results on two exploration wells, Laphroaig and Hurricane Deep. The Laphroaig well was deepened to 19,060 feet and encountered 56 net feet of hydrocarbon bearing sands. The Hurricane Deep well was drilled to a total depth of 20,713 feet and encountered 50 net feet of hydrocarbon bearing sands. Both of these discoveries are near existing infrastructure and can be brought online quickly.

We expect to drill eight to 10 exploratory prospects during 2007. Drilling has commenced at the Cas prospect at South Timbalier Block 70 and the Cottonwood Point prospect at Vermilion Block 31. Other prospects expected to be drilled in 2007 include the Mound Point South prospect on Louisiana State Lease 340, the Flatrock prospect at South Marsh Island Block 212, and the Deep Cavallo prospect at Matagorda Island Blocks 526/527.

We are excited about our exploration prospects and will continue these efforts during 2007 to expose shareholders to values we believe are available through drilling high impact wells in our focused exploration areas.

Main Pass Energy Hub™ (MPEH™)

We are enthusiastic about significant value realizable by establishing a major new offshore LNG terminal and onsite natural gas storage facility at the site of our former sulphur mine at Main Pass Block 299.



LNG Project Clears License Approval

McMoRan's efforts to establish a new Liquefied Natural Gas (LNG) deepwater port moved an important step toward fruition in January 2007, when the U.S. Maritime Administration (MARAD) approved McMoRan's license application for the Main Pass Energy Hub ™ project. The proposed project will help meet expanding natural gas demand in North America by opening a new gateway for the importation of LNG in the Gulf of Mexico.

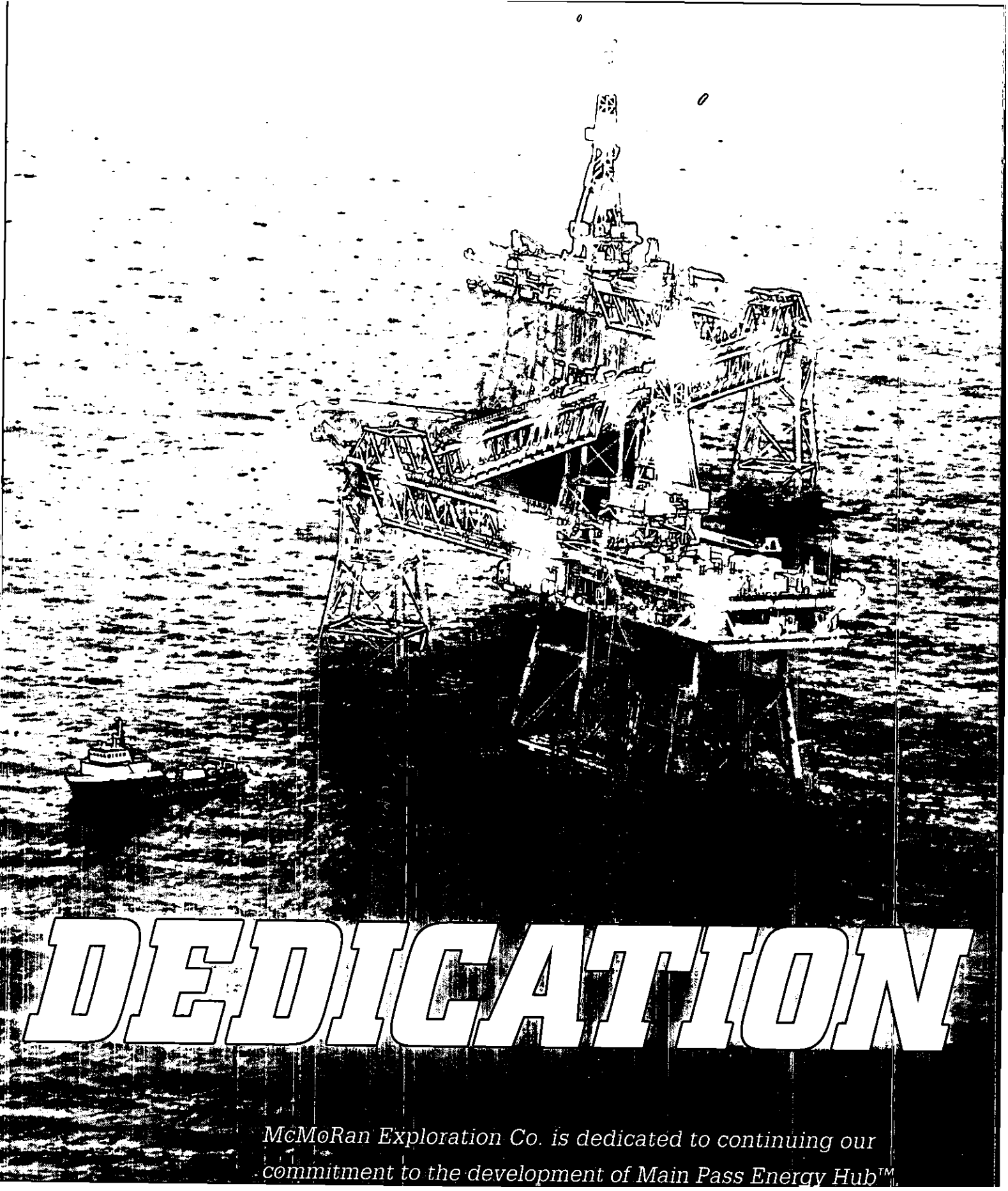
MARAD concluded in its Record of Decision that construction and operation of the Main Pass Energy Hub™ (MPEH™) deepwater port will be in the national interest and consistent with national security and other national policy goals and objectives, including energy sufficiency and environmental quality. MARAD also concluded that the MPEH™ will fill a vital role in meeting national energy requirements for many years to come and that the port's offshore deepwater location will help reduce congestion and enhance safety in receiving LNG cargoes to the U.S.

The application approval is an important milestone as McMoRan continues to pursue the highly attractive commercial potential for the project. The proposed deepwater port location is at Main Pass Block 299, at the site of our former sulphur mine. One of the many unique advantages of this location is our existing infrastructure — massive steel structures rising 120 feet above federal waters in the Gulf of Mexico, 16 miles offshore Southeast Louisiana and 38 miles east of Venice, Louisiana. These structures will become the backbone of the deepwater port and facilities to convert LNG back into natural gas at a peak rate of 1.6 billion cubic feet (Bcf) per day.

Another distinct advantage of the MPEH™ location is the ability to store natural gas in caverns within a massive salt dome beneath the platforms. The significant onsite storage, combined with the proximity of the project to major natural gas markets, provides a highly attractive commercial opportunity to expand the project beyond a typical LNG facility. The proposed design includes 28 Bcf of initial cavern storage availability and aggregate peak deliverability from the proposed terminal, including deliveries from storage, of up to 3.1 Bcf per day. The innovative terminal design includes a patent pending Soft Berth™ process, allowing efficient offloading of LNG from tankers.

McMoRan is continuing discussions with potential LNG suppliers as well as gas marketers and consumers in the United States to develop commercial arrangements for the facilities. Prior to commencing construction of the facility, McMoRan expects to enter into commercial arrangements that would enable McMoRan to finance the construction costs of the project, projected to cost $1 billion (approximately half of which is for pipelines and cavern storage) based on preliminary engineering completed in 2003.

Importing more LNG will help the Gulf Coast chemical and manufacturing industries, which have been impacted by high natural gas costs. The Center for Energy Studies at Louisiana State University estimates that more than 60,000 jobs in Louisiana alone could be lost if LNG import capability is not expanded. The MPEH™ project will have a direct and immediate impact on the economies of Louisiana and the Gulf Coast region, providing thousands of construction jobs and more than 1,000 direct and secondary long-term jobs. The University of New Orleans estimates the project will have a multi-billion dollar total economic impact, providing a much-needed boost for the Gulf Coast region.


DEDICATION
McMoRan Exploration Co. is dedicated to continuing our
commitment to the development of Main Pass Energy Hub™

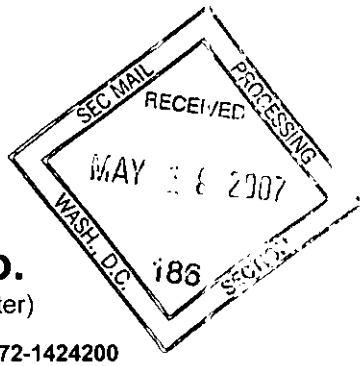
McMoRan Exploration Co.

2006 FORM 10-K

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

FORM 10-K

(Mark One)
[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2006
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)	(IRS Employer Identification No.)
1615 Poydras Street **New Orleans, Louisiana**	**70112**
(Address of principal executive offices)	(Zip Code)

(504) 582-4000

Securities registered pursuant to Section 12(b) of the Act:
(Registrant's telephone number, including area code)

Title of each class	**Name of each exchange on which registered**
Common Stock, par value $0.01 per share	New York Stock Exchange
Preferred Stock Purchase Rights	New York Stock Exchange
6% Convertible Senior Notes due 2008	New York Stock Exchange
5¼% Convertible Senior Notes due 2012	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act
☐ Yes ☒No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
☐ Yes ☒No

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 ☐ No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Act).
☐ Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer

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

The aggregate market value of classes of common stock held by non-affiliates of the registrant was approximately $229 million on February 28, 2007, and approximately $307 million on June 30, 2006.

On February 28, 2007, there were issued and outstanding 28,315,635 shares of the registrant's Common Stock and on June 30, 2006, there were issued and outstanding 28,294,179 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of our Proxy Statement for our 2007 Annual Meeting to be held on April 26, 2007 are incorporated by reference into Part III (Items 10, 11, 12, 13 and 14) of this report.

McMoRan Exploration Co.
Annual Report on Form 10-K for
the Fiscal Year ended December 31, 2006

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PART I

Items 1. and 2. Business and Properties

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

OVERVIEW

We have provided definitions for some of the industry terms we use in a glossary beginning on page 20.

About the Company. We engage in the exploration, development and production of oil and natural gas offshore in the Gulf of Mexico and onshore in the Gulf Coast region, with a focus on the potentially significant hydrocarbons we believe are contained in large, deep geologic structures often located beneath shallow reservoirs where significant reserves have been produced, commonly known as "deep gas." We are also pursuing plans for the development of liquefied natural gas (LNG) facilities at the Main Pass Energy Hub™ (MPEH™) project using our former sulphur facilities at Main Pass Block 299 (Main Pass) in the Gulf of Mexico. We were previously engaged in the mining of sulphur until August 2000 and discontinued other sulphur business activities in June 2002.

Subsidiaries. We have two wholly owned subsidiaries through which we conduct our business: McMoRan Oil & Gas LLC (MOXY), which conducts our oil and gas operations, and Freeport-McMoRan Energy LLC (Freeport Energy), which is pursuing the development of the MPEH™ project.

Business Strategy. Our business strategy is to pursue oil and natural gas exploration and development opportunities in the shallow waters of the Gulf of Mexico and onshore in the Gulf Coast region, primarily high-risk, high-potential, deep-gas exploration prospects and to develop the MPEH™ project.

Industry experts project declines in natural gas production from traditional sources in the U.S. and Canada, and significant increases in U.S. natural gas demand over the next 20 years. As a result, most industry observers believe that it is unlikely that U.S. demand can continue to be met entirely by traditional sources of supply. Accordingly, industry experts project that, non-traditional sources of natural gas, such as Alaska, the Canadian Arctic, the deep shelf, tight sands gas, shale gas, coal seam methane and LNG, will provide a significantly larger share of natural gas supply. We believe that we are well positioned to pursue two of these alternative natural gas supply sources, namely deep shelf production and LNG imports, by exploiting our exploration acreage and developing the MPEH™ project.

We believe we are well positioned to pursue our oil and natural gas exploration and development opportunities because of the following:

- Our success in drilling deep-gas exploratory wells on the shelf of the Gulf of Mexico and onshore in the Gulf Coast region is providing opportunities to partner with other established oil and gas companies to participate in our identified exploration prospects as well as partner with them in additional exploratory prospects (see "Oil and Gas Operations – Exploration Agreements" below);

- We possess a significant exploration acreage portfolio in the Gulf of Mexico and Gulf Coast region (see Oil and Gas Operations – Acreage" below);

- We have a broad-based team with significant experience in the use of structural geology augmented by 3-D seismic technology and in drilling deep gas prospects;

- We own or have rights to an extensive seismic database, including 3-D seismic data on substantially all of our acreage;

- We have conducted intensive evaluations of our acreage and have identified over 20 exploration prospects, most of which are high-risk, high-potential, deep-gas prospects; and

- We have participated in important discoveries in an area where we control over 150,000 gross acres within OCS 310 and Louisiana State Lease 340. To date, we have drilled a total of seven successful wells at the Hurricane, Hurricane Deep, JB Mountain and Mound Point prospects and we have two additional potential discoveries at the Blueberry Hill and JB Mountain Deep prospects that require additional evaluation (see "Oil and Gas Operations – Discoveries and Development Activities" below). We have also identified multiple additional drilling opportunities within this acreage position.

We also believe that we are well positioned to pursue our MPEH™ project because of the following:

- We have offshore platform facilities with an adjacent two-mile diameter salt dome that are strategically located in an area we believe is suitable for the development of MPEH™ as a LNG deepwater port facility with onsite cavern storage for natural gas;

- We have completed preliminary engineering for the MPEH™ project and the related license application was approved in January 2007;

- The MPEH™ project has unique advantages including the use of existing offshore structures, onsite natural gas cavern storage capabilities, significant logistical savings associated with the offshore location and access to premium natural gas markets from its eastern Gulf of Mexico location. These advantages would provide LNG suppliers with a highly attractive netback price and offer U.S. natural gas consumers a reliable source of supply; and

- The development of commercial arrangements for LNG supplies and distribution of natural gas and financing for the project could enable our project to become operational as one of the first U.S. offshore LNG terminals.

For more information regarding our MPEH™ project see "Main Pass Energy Hub™ Project" below.

OIL AND GAS OPERATIONS

Background. We and our predecessors have engaged in oil and natural gas exploration and production in the Gulf of Mexico and the Gulf Coast region for over 35 years. We have focused on this region because:

- We have developed significant expertise and have an extensive database of information about the geology and geophysics of this region;

- We believe there are significant reserves in this region that have not yet been discovered; and

- The necessary infrastructure for efficiently developing, producing and transporting oil and natural gas exists in this region, which allows an operator the opportunity to reduce costs and the time that it takes to develop, produce and transport oil and natural gas.

Our primary focus in this region is on deep gas exploration and production opportunities in the shallow water and onshore. We consider deep gas to be geologic structures located beneath the shallow waters of the Gulf of Mexico shelf and onshore at underground depths generally greater than 15,000 feet and often lying below reservoirs that have previously produced significant hydrocarbons. We believe that the U.S. market for natural gas has become increasingly attractive as demand continues to grow faster than available domestic and Canadian supplies. We also believe that deep natural gas targets on the shelf of the Gulf of Mexico and onshore in the Gulf Coast region provide attractive drilling opportunities because the shallow water depths and/or close proximity to existing oil and natural gas production infrastructure allows discoveries to have the potential to generate production and cash flow relatively quickly.

Exploration Agreements. In the fourth quarter of 2006, we entered into an exploration agreement with Plains Exploration & Production Co. (Plains) whereby Plains will participate in up to nine of our exploration prospects for approximately 55 percent to 60 percent of our initial ownership interests in the prospects. Subsequent elections may increase Plains' participation in certain of these prospects. The first two prospects under this agreement commenced drilling in the fourth quarter of 2006 and as of the date of this filing, two additional exploratory wells have commenced drilling in the first quarter of 2007. Prior to entering into this agreement we completed an aggregate $500 million exploration agreement with a private partner.

Our exploration agreements have and will continue to enable us to pursue significant drilling and development activities. Since 2004, we have participated in 15 discoveries on the 29 prospects that have been drilled and fully evaluated. Testing and evaluation of the Blueberry Hill well at Louisiana State Lease 340 is in progress and its results will be incorporated into future plans for the JB Mountain Deep well at South Marsh Island Block 224.

Oil and Gas Properties. As of December 31, 2006, we owned or controlled interests in approximately 400 oil and gas leases in the Gulf of Mexico and onshore in Louisiana and Texas covering approximately 370,000 gross acres (approximately 132,000 acres net to our interests). This acreage includes approximately 13,000 gross and 3,000 net acres associated with our potential reversionary interests.

In January 2006, we negotiated a farm-in transaction that provides us exploration rights to over 100,000 gross acres in southern Louisiana and on the Gulf of Mexico shelf. This five-year agreement allows us to earn acreage by drilling a specified minimum number of wells. Under this arrangement, the original lease owner may elect to participate in certain wells after casing point and may elect to participate in other wells as a joint interest owner.

In June 2005, we acquired oil and gas rights from El Paso Production Company, a subsidiary of El Paso Corporation, covering six deep-gas exploration prospects on approximately 18,000 gross acres onshore and in state waters in Vermilion Parish, Louisiana. We have drilled exploratory wells at four of the six prospects, resulting in discoveries at Long Point at Louisiana State Lease 18090, Cane Ridge at Louisiana State Lease 18055, Liberty Canal and Zigler Canal. Production has commenced from all four of these prospects although the Cane Ridge well is currently shut-in while remedial operations are in progress.

In 2004, we reacquired rights involving approximately 45,000 gross acres in the Louisiana State Lease 340/Mound Point and OCS 310/JB Mountain areas (see "Farm-Out Arrangement with El Paso" below). This reacquired acreage includes the Hurricane, Hurricane Deep and JB Mountain Deep prospects at OCS 310, the Blueberry Hill prospect and two Mound Point wells that were previously temporarily abandoned all of which are located within Louisiana State Lease 340. We are considering future operations with respect to the temporarily abandoned Mound Point wells, which may include sidetracking, deepening or re-drilling these two wells.

Ryder Scott Company, L.P., an independent petroleum engineering firm, estimated our proved oil and natural gas reserves at December 31, 2006 to be 75.8 Bcfe, consisting of 41.2 Bcf of natural gas and 5.8 MMBbls of crude oil and condensate using the definitions required by the SEC. These estimated amounts include approximately 4.5 MMBbls (26.8 Bcfe) of crude oil associated with Main Pass (see "Producing Properties" below) and 18.8 Bcfe of proved reserves associated with our discoveries in 2006. For additional information regarding our estimated reserves, see "Oil and Gas Reserves" below and Note 12. Our production during 2006 totaled approximately 14.5 Bcf of natural gas and 1.6 MMBbls of oil and condensate or an aggregate of 23.9 Bcfe.

Producing Properties.
The table below sets forth approximate information, as of December 31, 2006, with respect to our producing properties and the two remaining prospects included in our farm-out arrangement. Average daily production from our properties, net to our interests, approximated 65 MMcfe/d in 2006 compared with 36 MMcfe/d in 2005. We estimate our net share of first quarter 2007 production will average 70-80 MMcfe/d. For additional oil and gas property information, including our discoveries that commenced production in 2005 and 2006 see "Discoveries and Development Activities," "Other" and "Disposition of Oil and Gas Properties" below.

Field, Lease or Well	Working Interest (%)	Net Revenue Interest (%)	Operator	Water Depth (in feet)	Location Offshore Louisiana (miles)	Gross Acreage
Main Pass Block 299 [a]	100	83.3	MMR [b]	210	32	1,125
Eugene Island Blocks 193/215	53.4	42.3	MMR	100	50	7,500
Eugene Island Blocks 97/108 (Thunderbolt)	38.0	27.2	DVN [c]	90	50	9,375
Ship Shoal Block 296 (Raptor)	49.4	34.8	APA [d]	260	62	5,000
Main Pass Blocks 86 (Shiner)	53.4	38.5	MMR	70	45	4,995
Vermilion Block 196 (Lombardi)	35.6	25.7	Superior	115	50	5,000
West Cameron Block 616	25.0	19.3	Tarpon	300	130	5,000
Discoveries after 2004 [e]						
Eugene Island Block 193 (C-2)	48.6	45.3	MMR	90	50	7,500
Eugene Island Block 213 (Minuteman)	33.3	29.8	NHY [f]	100	40	9,000
South Marsh Island Block 217 (Hurricane)	27.5	29.8	CVX [g]	10	9	7,700
Vermilion Block 16 (King Kong)	40.0	29.2	MMR	13	2	3,323
Louisiana State Lease 18055 (Cane Ridge)	50.0	36.8	MMR	n/a	n/a	1,099
Louisiana State Lease 18090 (Long Point)	37.5	26.7	EP	8	n/a	5,000
Garden Banks 625 (Dawson Deep)	30.0	24.0	ANA	2,900	n/a [h]	5,760
Vermilion Parish, LA (West Pecan Island)	50.0	36.0	MMR	10	n/a	1,710
High Island Block 131 (King of Hill)	25.0	23.8	Gryphon	40	27	5,760
Vermilion Parish, LA (Liberty Canal)	37.5	27.7	EP	n/a	n/a	1,424
St. Mary Parish, LA (Point Chevreuil)	25.0	17.5	Palace	<10	n/a	4,303
Vermilion Parish, LA (Zigler Canal)	50.0	35.8	MMR	n/a	n/a	640
Farm-out [i]						
South Marsh Island Block 223 (JB Mountain)	55.0	38.8	CVX	10		-
Louisiana State Lease 340 (Mound Point)	30.4	21.6	CVX	10		-

a. In December 2004, we acquired the 66.7 percent equity interest in a joint venture not previously owned by us. For additional information see Items 7. and 7A. "Main Pass Oil Facilities" and Note 4 located elsewhere in this Form 10-K.
b. MMR is our New York Stock Exchange ticker symbol.
c. Devon Energy Corporation.
d. Apache Corp.
e. For a discussion of these properties see "Discoveries and Development Activities" below.
f. Hydro Gulf of Mexico, LLC, a wholly owned subsidiary of Norsk Hydro ADR. We operate the field's production operations under terms of a contract.
g. Chevron Corporation. Chevron is the operator of the producing wells at Hurricane, JB Mountain and Mound Point.
h. Dawson Deep is located 150 miles offshore Texas.
i. In May 2002, we entered into an exploration arrangement with El Paso covering these deep-gas prospects. In the farm-out agreement we retained a potential 50 percent reversionary interest in these prospects, which would revert to us when the aggregate production from the prospects, net to the program's net revenue interests, exceeds 100 Bcfe. These prospects are located in an area

where we participate in a program that controls an approximate 13,000-acre area on portions of Louisiana State Lease 340 and OCS 310.

- **Main Pass Block 299.** We originally acquired the Main Pass oil operations in November 1998. In December 2002, we sold our interest in the Main Pass oil operations to a joint venture, in which we retained a 33.3 percent equity interest. On December 27, 2004, we acquired the 66.7 percent ownership interest in the joint venture that we did not own and now own 100 percent of the Main Pass oil operations. For more information regarding the joint venture transactions see Items 7. and 7A. "Main Pass Oil Facilities" and Note 4 located elsewhere in this Form 10-K.

  In September 2004, the storm center of Hurricane Ivan passed within 20 miles east of Main Pass. The Main Pass structures did not incur significant damage from Ivan but oil production from Main Pass was shut-in because of extensive damage to a third-party offshore terminal and connecting pipelines that provided throughput service for the sale of Main Pass's sour crude oil. In May 2005 production resumed at Main Pass following successful modification of existing facilities at one structure formerly used in our discontinued sulphur mining business to accommodate transportation of oil production from the field by barge.

  On August 29, 2005, the storm center of Hurricane Katrina passed within 50 miles west of Main Pass. While the Mass Pass facilities and platforms did not sustain significant damage from Katrina, oil operations were temporarily shut-in to perform required repairs caused by the storm. Main Pass resumed oil production in late November 2005. Subsurface inspections at Main Pass that commenced during the fourth quarter of 2005 indicated the primary oil structures did not sustain any significant structural damage from the storm but identified one ancillary structure that required repairs, which were successfully performed during 2006.

  As of December 31, 2006, cumulative gross production from the Main Pass oil operations totaled approximately 47.2 MMBbls. The original owner of the Main Pass oil lease is entitled to a 6.25 percent overriding royalty in any new wells drilled on the lease.

- **Eugene Island Blocks 193/215.** During 2000, we performed remedial and recompletion work that reestablished production from the field and identified additional proved reserves. We performed additional recompletion work during each of the three years ended December 31, 2006, including work performed at the Eugene Island Block 193 C-1 Sidetrack and C-2 wells in the fourth quarter of 2006 (see "Discoveries and Development Activities" below).

- **Eugene Island Blocks 97 and 108.** During 2000 and 2001, we drilled three successful exploratory wells at this prospect. Two of the wells commenced production in 2001 and the third well commenced production in January 2002. The wells have been shut-in periodically in order to perform recompletion work to establish production from new intervals. We currently have intermittent production from only one well; one well's proved reserves are fully depleted and the third well has been shut-in since Hurricane Rita in September 2005. During 2006, initial attempts to reestablish production from the shut-in well were unsuccessful. Another attempt to reestablish production from the shut-in well is planned for the first quarter of 2007.

- **Ship Shoal Block 296.** In 2000, we drilled two productive wells at the Raptor prospect, with production commencing during 2001. We sold 80 percent of our original 61.8 percent working interest and 43.5 percent net revenue interest in February 2002 (see "Disposition of Oil and Gas Properties" below and Note 4). In the first quarter of 2005, we performed recompletion work and restored production to one well. The third-party purchaser assigned to us the 75 percent reversionary interest in Raptor effective February 1, 2005. On January 1, 2006, a development well was spud at the Raptor location. The A-3 well reached its total planned depth of 9,200 feet, was completed, and commenced production on February 12, 2006. The A-4 development well commenced drilling on February 9, 2006. The A-4 well reached its total planned depth of 7,405 feet, was completed, and commenced production on March 4, 2006.

- **Main Pass Block 86.** During 2000, we announced two successful exploratory wells at the Shiner prospect. We sold the property in February 2002 but retained a reversionary interest in the well (see "Disposition of Oil and Gas Properties" below). Initial production from the No. 2 well occurred in June

2004 and from the No. 1 well in March 2005. The interests that we own reverted to us effective June 1, 2005 following the achievement of payout.

- **Vermilion Block 196.** In 2000, we drilled the Lombardi No. 2 exploratory well to a total depth of 14,798 feet. We developed the well and initial production commenced in 2001. We sold the property in 2002 but retained a reversionary interest (see "Disposition of Oil and Gas Properties" below). Production from the field increased during 2003 following the successful drilling and development of additional exploratory wells. The interests that we own reverted to us effective June 1, 2005 following the achievement of payout.

- **West Cameron Block 616.** We discovered this field in 1996. Production commenced at the field from five well completions in March 1999. Production from the field ceased in February 2002 and we farmed out our interests to a third party in June 2002. The third party drilled four successful wells and production from the field re-commenced during the first quarter of 2003. We retained a 5 percent overriding royalty interest, subject to adjustment, after aggregate production exceeded 12 Bcf of gas, net to the acquired interests. When aggregate production exceeded this threshold in September 2004, we exercised our option to convert to a 25 percent working interest and a 19.3 percent net revenue interest in three of the wells in the field and to a 10 percent overriding royalty interest in the fourth well.

Discoveries and Development Activities. Since 2004, we have participated in 15 discoveries and potential additional discoveries at Blueberry Hill and JB Mountain Deep, which are summarized below.

	Working Interest	Net Revenue Interest	Water Depth	Total Depth	Initial Production
	%	%	feet	feet	Date
2005 Discoveries:					
Eugene Island Block 193 "Deep Tern C-2" [a]	48.6	45.3[b]	90	20,731	December 30, 2004
Eugene Island Block 213 "Minuteman"	33.3	29.8[b]	100	20,432	February 25, 2005
South Marsh Island Block 217 "Hurricane" [c]	27.5	19.4	10	19,664	March 30, 2005
Vermilion Blocks 16/17 "King Kong" [a,d]	40.0	29.2	13	18,918	December 22, 2005
Louisiana State Lease 18055 "Cane Ridge" [a]	50.0	36.8	n/a [e]	16,450	April 21, 2006
Louisiana State Lease 18090 "Long Point" [c,f]	37.5	26.7	8	19,000	May 22, 2006
Garden Banks Block 625 "Dawson Deep"	30.0	24.0	2,900	22,790	July 6, 2006
West Cameron Block 43 (No.3)[g]	23.4	21.9[b]	30	18,800	January 18, 2007
2006 Discoveries:					
West Pecan Island "Pecos" [a]	50.0	36.0	10	18,795	August 4, 2006
High Island Block 131 "King of the Hill"	25.0	23.8[b]	40	16,290	August 22, 2006
Onshore Vermilion Parish, LA "Liberty Canal" [a]	37.5	27.7	n/a [e]	16,594	October 2, 2006
St. Mary Parish, LA "Point Chevreuil"	25.0	17.5	<10	17,011	December 22, 2006
Onshore Vermilion Parish, LA "Zigler Canal" [a]	50.0	35.8	n/a [e]	13,635	December 30, 2006

	Working Interest	Net Revenue Interest	Water Depth	Total Depth	Initial Production
	%	%	feet	feet	Date
St. Mary Parish, LA "Laphroaig" [a]	50.0	38.5	<10	19,060	Mid-Year 2007
South Marsh Island Block 217 "Hurricane Deep" [a,c]	25.0	20.8[b]	<10	21,500	Mid-Year 2007
Potential Discovery					
Louisiana State Lease 340 "Blueberry Hill" [a]	49.0	33.9	10	23,903	Pending Test Results & Development Plan
South Marsh Island Block 224 "JB Mountain Deep" [a]	35.0	24.8	10	5,195	Pending Results from Blueberry Hill well

a. Wells operated by us.
b. Reflects the eligibility for deep gas royalty relief under current MMS guidelines adopted effective March 1, 2004. The guidelines exempt from U.S. government royalties production of as much as the first 25 Bcf from a depth of 18,000 feet or greater, and as much as 15 Bcf from depths between 15,000 and 18,000 feet, with gas production from all qualified wells on a lease counting towards the volume eligible for royalty relief. The exact amount of royalty relief depends on eligibility criteria, which include the well depth, nature of the well, and the timing of drilling and production. In addition, the guidelines include price threshold provisions that discontinue royalty relief if natural gas prices exceed a specified level. The price threshold was not exceeded during either 2006 or 2005.
c. We operated the drilling of the exploratory well at these prospects. We relinquished being operator following successful completion of the related wells. El Paso is the current operator of the Long Point wells. Chevron Corporation is current operator of the Hurricane wells. Chevron will operate the Hurricane Deep well following its completion.
d. Table reflects information for the King Kong No. 1 discovery well. The King Kong No. 2 development well commenced production on December 30, 2005 and the King Kong No. 3 development well commenced production on April 27, 2006. All three wells have the same working and net revenue interests.
e. Prospect is located onshore Vermilion Parish, Louisiana.
f. Table reflects information for the Long Point No. 1 discovery well. The Long Point No. 2 development well commenced production on May 27, 2006. Both wells have the same working and net revenue interests.
g. We drilled a second exploratory well at West Cameron Block 43. The No. 4 well was drilled to a total depth of 18,500 feet. We have a 41.7 percent working interest and 39.2 percent net revenue interest in the No. 4 well.

- **Eugene Island Block 193.** In November 2004, the Deep Tern C-2 well logged approximately 340 gross feet of hydrocarbons in five Basal Pliocene and Upper Miocene pay zones. The Eugene Island Block 193 lease is eligible for royalty relief on the first 10 Bcf of natural gas production. At December 31, 2006, approximately 5.4 Bcf of natural gas has been produced from the C-2 well. When gross production exceeds 10 Bcf, our net revenue interest for natural gas would revert to 37.2 percent in the deeper Basal Pliocene and Upper Miocene sections of the well. Our net revenue interest for oil production is 37.2 percent.

  In January 2005, drilling of the Deep Tern C-1 sidetrack well commenced. The well reached a total depth of 17,080 feet in April 2005. We hold a 20.6 percent net revenue interest in the C-1 sidetrack well, which commenced production on April 29, 2005. We control 17,500 acres in the Deep Tern area, which is located approximately 50 miles offshore Louisiana.

- **Eugene Island Block 213.** Following start-up operations, gross daily production decreased to approximately 3 MMcfe/d and was shut-in on various occasions because of mechanical and/or hurricane-related events. The well is currently producing at significantly reduced rates. The Eugene Island Block 213 lease is eligible for royalty relief on the first 25 Bcf of natural gas production. At December 31, 2006, approximately 1.5 Bcf has been produced at the Eugene Island Block 213 lease. When gross production of natural gas exceeds 25 Bcf, our net revenue interest would revert to 24.3 percent. Our net revenue interest for oil production is 24.3 percent.

We control 9,600 acres in this prospect area, which is located approximately 40 miles offshore Louisiana.

- **South Marsh Island Block 217.** In January 2005, the Hurricane prospect logged approximately 205 gross feet of hydrocarbons in two Rob-L pay zones. The well was shut-in for 45 days in 2005 primarily because of the effects of Hurricanes Katrina and Rita. Production is processed through the Tiger Shoal facilities, which also are used to process the production of the Mound Point/JB Mountain wells (see "Farm-Out Arrangement with El Paso" below). During 2006, we drilled two development wells, Hurricane Nos. 2 (total depth 14,000 feet) and 3 (total depth 16,000 feet). The Hurricane No. 2 well commenced production on April 27, 2006 and the No. 3 well commenced production on November 29, 2006. The No. 3 well is currently shut-in; however, a recompletion to the next sand interval is expected to commence prior to the end of the first quarter of 2007.

  The Hurricane Deep exploratory well commenced drilling on October 26, 2006 and was drilled to a true vertical depth of 20,713 feet in February 2007. Log-while-drilling tools indicated that a thick upper Gyrodina (Gyro) sand was encountered totaling 900 gross feet. The top of this Gyro sand is credited with a potential of 50 feet of net hydrocarbons in a 53 foot gross interval. These sand thicknesses suggest that prospects in the Mound Point, JB Mountain, Hurricane and Blueberry Hill area may have thick sands as potential Gyro reservoirs. Additionally, previous wireline logs have indicated 27 net feet of hydrocarbon bearing sands over a 200 foot gross interval in a laminated Rob-L section and a potential 20 net feet of hydrocarbon bearing sands over a 70 foot gross interval in the Operc section. The well could be brought on quickly using the Tiger Shoal production facilities. We control 7,700 gross acres in this area. This well would be our seventh successful well in the OCS 310/Louisiana State Lease 340 area.

  The South Marsh Island Block 217 lease is eligible for royalty relief on the initial 15 Bcf of natural gas production for wells drilled and produced at depths exceeding 15,000 feet. Our Hurricane Deep well qualifies for this relief. When gross production of natural gas exceeds 15 Bcf, our net revenue interest for the Hurricane Deep well would revert to 17.7 percent. Our net revenue interest for oil production is 17.7 percent for the Hurricane Deep well.

- **Vermilion Blocks 16/17.** The King Kong No. 1 discovery well commenced drilling in February 2005 and wireline logs indicated 14 hydrocarbon bearing sands totaling approximately 150 feet of net pay. In August 2005, a successful production test at King Kong No. 1 was conducted.

  The King Kong No. 2 development well commenced drilling in August 2005 and was drilled to a total depth of 13,680 feet. Log-while-drilling tools indicated the well encountered approximately 100 feet of possible hydrocarbon bearing sands. The King Kong No. 2 development well is a direct offset mapped updip to the King Kong No. 1 discovery well.

  The King Kong No. 3 development well commenced drilling in November 2005 and was drilled to a total depth of 16,142 feet. The well is a southwest offset to the No. 1 discovery well. The well was evaluated with log-while-drilling tools and confirmed with wireline logs to 13,500 feet, indicating multiple Miocene sands approximating 60 net feet of hydrocarbons.

  Production from the King Kong Nos. 1 and 2 wells commenced in December 2005. The King Kong No 3 well commenced production in April 2006. The No. 2 well was shut-in at December 31, 2006. A recompletion to the next sand interval was completed and production resumed in February 2007.

- **Louisiana State Lease 18055.** The Cane Ridge exploratory well commenced drilling in July 2005 and wireline logs indicated multiple hydrocarbon bearing sands approximating 60 net true vertical feet of resistivity. The well commenced production at initial rates approximating 9 MMcfe/d, which decreased significantly after a few weeks of production. In early July the well was shut-in and initial attempts to reestablish production were unsuccessful. In late December 2006, the operator relinquished its ownership rights to us and our private exploration partner. We were appointed operator and are currently performing remedial operations.

- **Louisiana State Lease 18090.** The Long Point exploratory well, located in the state waters of Vermilion Parish, Louisiana, commenced drilling in July 2005 and was drilled to 19,000 feet and evaluated with log-while-drilling tools and wireline logs, indicating an interval approximating 150 gross feet of hydrocarbon bearing sands. The wireline log indicated excellent porosity. In November 2005, we conducted a successful production test.

  The Long Point No. 2 development well commenced drilling in November 2005 and was drilled to a total depth of 19,617 feet. The well encountered three additional pay zones. The production rate at the No. 2 well increased significantly in November 2006 following completion of remedial activities at the well.

- **Garden Banks Block 625.** Completion operations at the Dawson Deep well commenced in January 2006 and a sidetrack of the well commenced drilling in February 2006. The Dawson Deep well encountered hydrocarbon bearing sands as indicated by more than 100 feet of total vertical thickness of resistivity in the shallow zones. An additional 100 feet of hydrocarbons were logged in the deepest zone which was the original objective of this well. This prospect is located on a 5,760 acre block located approximately 150 miles offshore Texas and is adjacent to the operator's Gunnison spar facility.

- **West Cameron Block 43.** The No. 3 exploratory well commenced drilling in November 2004 and wireline logs indicated three hydrocarbon bearing sands in the lower Miocene with a total gross interval in excess of 100 feet. In April 2005, drilling commenced on a second exploratory well (West Cameron Block 43 No. 4), which is located 4,000 feet north of the No. 3 well. The No. 4 well was drilled to a total depth of 18,500 feet and encountered several sands that appeared to be hydrocarbon bearing. Following an initial successful production test, the No. 4 well experienced mechanical difficulties and was temporarily abandoned while efforts to establish production at the No. 3 well were initiated.

  At December 31, 2006, limited quantities of proved reserves were initially assigned to this field, pending production history to support additional reserves. As indicated in our fourth-quarter 2006 financials results release on January 18, 2007, we were monitoring our investment in the West Cameron Block 43 field, which was in start-up operations and expected to be completed in the near-term. In late January 2007, production commenced at the No. 3 well at lower than anticipated flow rates. The well's production decreased steadily and it shut-in late in February 2007. Our current assessment is that it is unlikely that proved reserves attributed to the field at December 31, 2006 will be recovered. We will continue to assess possible alternatives to restore production to the No. 3 well which, if performed with successful results, could be incorporated into potential plans for the No. 4 well. The West Cameron Block 43 lease is located 8 miles offshore Louisiana.

- **West Pecan Island, Vermilion Parish, LA**. The Pecos exploratory well commenced drilling on January 5, 2006 and uphole pay sands were evaluated with log-while-drilling tools and wireline logs, indicating two intervals of hydrocarbons. The deeper zone encountered 31 net feet of hydrocarbon bearing sands over a 172 foot gross interval; the upper zone entered 12 net feet of hydrocarbon bearing sands over a 14 foot gross interval. The well uses the facilities at the nearby King Kong facilities at Vermilion Block 16. In late February 2007, the well was shut-in. We are currently performing work to reestablish production from the well. We have rights to approximately 3,500 acres in this area, which includes both the Pecos prospect and the Platte exploration prospect.

- **High Island Block 131.** The King of the Hill No. 2 exploratory well commenced drilling on January 28, 2006 and encountered 130 net feet of hydrocarbon bearing sands. The High Island Block 131 lease, located 27 miles offshore Louisiana, is eligible for royalty relief on the first 15 Bcf of natural gas production. As of December 31, 2006, 2.4 Bcf of natural gas has been produced for this well. Our net revenue interest for natural gas production is currently 23.8 percent and will decrease to 19.6 percent after 15 Bcf of natural gas is produced. Our net revenue interest for oil production is 19.6 percent.

- **Liberty Canal, Onshore Vermilion, Parish LA**. The Liberty Canal exploratory well commenced drilling on March 5, 2006 and was evaluated with log-while-drilling tools and confirmed with

wireline logs, which indicated two intervals totaling 199 gross feet with 125 net feet of hydrocarbon bearing sands. The Liberty Canal discovery is located onshore Vermilion Parish, Louisiana on a significant north-south ridge where we control approximately 13,000 acres. We incorporated the results from this well together with our 3-D seismic data to develop the Zigler Canal discovery (see below) located two miles northwest of the Liberty Canal discovery. We are continuing to evaluate this 13,000-acre area and expect to identify additional exploration prospects.

- **Point Chevreuil, St. Mary Parish, LA.** The Point Chevreuil exploratory well commenced drilling on November 18, 2005 and was evaluated with log-while-drilling tools and confirmed with wireline logs, which indicated 96 net feet of hydrocarbon bearing sands over a 112 foot gross interval. In May 2006, we and our exploration partner acquired an additional approximate 2,500 gross acres surrounding this discovery.

- **Zigler Canal, Onshore Vermilion Parish, LA.** The Zigler Canal exploratory well commenced drilling on June 17, 2006 and was drilled to a total depth of 18,571 feet. The deeper objectives were determined to be nonproductive and the well was plugged back and sidetracked. The sidetrack well was drilled to a total depth of 13,635 feet and evaluated with log-while-drilling logs, which indicated a potential 30 net feet of hydrocarbon bearing sands over a 125 foot gross interval.

- **Laphroaig, St. Mary Parish, LA.** The Laphroaig exploratory well commenced drilling on April 8, 2006 and was sidetracked to a true vertical depth of 18,415 feet. Following an unsuccessful production test in February 2007, we and our partners deepened the well to test additional targets. Wireline logs have indicated that the well encountered a potential 56 net feet of hydrocarbon bearing sands over a 75 foot gross interval. The well can be brought on production promptly utilizing infrastructure in the area. We have rights to approximately 2,200 gross acres in this area.

- **Louisiana State Lease 340.** The Blueberry Hill well was drilled and wireline logs indicated four potentially productive hydrocarbon bearing sands. A 4½ inch production liner was run and cemented to protect the identified potential pay zones. We temporarily abandoned the well while the necessary 20,000-pound completion equipment for the anticipated high pressure well was procured. Delivery of this equipment occurred in the fourth quarter of 2006 and the completion and testing of the well commenced. The well has been perforated but production has not been established because of blockage above the perforated intervals. Additional operations to clear the blockage and complete testing of the well are expected in the near-term. Blueberry Hill is located seven miles east of the JB Mountain discovery and seven miles south southeast of the Mound Point Offset discovery (see "Farm-Out Arrangement with El Paso" below).

- **South Marsh Island Block 224.** The JB Mountain Deep prospect commenced drilling in July 2005 and reached a total depth of approximately 24,600 feet in April 2006. Wireline logs indicated 120 gross feet of potential hydrocarbon bearing sands at a depth of approximately 21,900 feet that will require further evaluation. Wireline logs also indicated an additional 115 gross feet of potential hydrocarbon bearing sands at a depth of approximately 24,250 feet. A liner was set to protect the lower zone and the well was temporarily abandoned. We control approximately 5,200 gross acres in the area, which is outside the area covered by the farm-out arrangement with El Paso. Information obtained from the completion and testing of the Blueberry Hill well will be incorporated in our future plans for the JB Mountain Deep prospect. Both areas demonstrate similar geologic settings and are targeting Deep Miocene sands that are equivalent in age.

Near-Term Drilling Activities. Over the past several years, we focused on identifying exploration prospects within our significant acreage position, as well as prospects from other industry participants. These efforts have resulted in the identification of over 20 high-potential, high-risk exploratory prospects, most of which are deep-gas targets near existing infrastructure in the shallow waters of the Gulf of Mexico and onshore in the Gulf Coast area. We are currently drilling two exploratory wells and anticipate drilling 8-10 exploratory wells during 2007. We expect our capital expenditures for 2007, net to our working interests, will approximate $150 million, including $40 million for exploration expenditures incurred during 2006. These costs are subject to change depending on the number of wells drilled, participant elections,

availability of drilling rigs, the time it takes to drill each well, related personnel and material costs, and other factors, many of which are beyond our control. For more information regarding the factors affecting our drilling operations see Item 1A. "Risk Factors."

If our exploratory drilling is successful, significant additional capital will be required for the development and completion of these prospects. In addition, we may have funding requirements under our farm-out arrangement with El Paso if and when interests in those prospects revert to us. While we have had success in our deep gas drilling program, there are substantial risks associated with oil and gas exploration. For additional information regarding those risks, see Item 1A. "Risk Factors."

The table below sets forth approximate information with respect to prospects we have commenced drilling. Plans to drill additional wells in 2007 are subject to change based on various factors, as described in Item 1A. "Risk Factors."

	Working Interest	Net Revenue Interest	Prospect Acreage [a]	Water Depth	Proposed Total Depth [b]	Current Depth [c]	Spud Date [d]
Exploration In-Progress:	%	%		feet	feet	feet	
South Timbalier Block 70 "Cas" [e]	15.0	12.4	5,000	20	25,000	5,000	January 30, 2007
Vermilion Block 31 "Cottonwood Point"	15.0	11.3	5,523	15	21,000	5,000	March 1, 2007
Near-Term Exploration Wells:							
Louisiana State Lease 340 "Mound Point South" [f]	18.3	14.5	6,400	8	20,000	n/a	First-Quarter 2007
South Marsh Island Block 212 "Flatrock" [f]	25.0	18.8	3,805	10	16,500	n/a	Second-Quarter 2007
Matagorda Island Blocks 526/557 "Deep Cavallo"	40.0	29.8	6,878	70	14,000	n/a	Mid-Year 2007

a. Gross acres encompassing prospect to which we retain exploration rights.
b. Planned target vertical depth, which is subject to change.
c. Approximate total depth of well on March 14, 2007.
d. The timing of spudding near-term wells is subject to change.
e. Depending upon applicability of Deep Gas Royalty Relief eligibility criteria, the lease on which these wells are located could be eligible for royalty relief on up to 25 Bcf of gas production under current Minerals Management Service (MMS) guidelines. Our net revenue interests would increase during the royalty relief period for eligible leases. For further discussion of royalty relief requirements see Note 1.
f. Wells in which we are or expect to be the operator.

Farm-Out Arrangement with El Paso. In May 2002, we entered into a farm-out agreement with El Paso for four of our shallow-water, deep-gas prospects. El Paso drilled exploratory wells at each prospect, resulting in two discoveries. El Paso has relinquished its rights to all but the 13,000 gross acres surrounding the JB Mountain and Mound Point Offset wells. Under the program, El Paso funds our share of the exploratory drilling and development costs of these prospects and will own 100 percent of the program's interests until the aggregate production attributable to the program's net revenue interests reaches 100 Bcfe. After aggregate production of 100 Bcfe, ownership of 50 percent of the program's working and net revenue interests would revert to us. The JB Mountain No. 1 well is currently shut-in, however a recompletion of the well is anticipated to be performed in the first quarter of 2007. We do not expect payout will occur in 2007.

- **"JB Mountain" at South Marsh Island Block 223.** Drilling commenced at the JB Mountain prospect in 2002. The No. 1 well was drilled to a measured depth of approximately 22,000 feet and evaluated with wireline logs and formation tests, which indicated significant intervals of hydrocarbon pay. The well was completed and production commenced in June 2003. The No. 2 well commenced in June 2003. The No. 2 well was subsequently completed and placed on production in January 2004.

- **"Mound Point Offset" at Louisiana State Lease 340.** Drilling commenced in 2003. The well was drilled to a total depth of approximately 19,000 feet and encountered 120 feet of net gas pay in three sands. Development activities were completed and the well commenced production in October 2003. The well 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).

The South Marsh Island Block 223 No. 221 (JB Mountain No. 3) well commenced drilling in December 2003 and was drilled to 14,688 feet. Prior to reaching the target objective the well experienced mechanical difficulties and was temporarily abandoned. The Louisiana State Lease 340 well (Mound Point Offset No. 2) commenced drilling in January 2004 and was drilled to 18,724 feet. After logging the well, which indicated the presence of both hydrocarbon bearing and wet sands, the well was temporarily abandoned. We acquired this well and the surrounding acreage in October 2004 (see "Oil and Gas Properties" above).

We believe significant further exploration and development opportunities exist in the JB Mountain and Mound Point areas.

Other.

- **Vermilion Block 160 Field Unit.** We commenced production from this field in 1995. Final production from the field occurred in the fourth quarter of 2005. Reclamation activities for the field are planned for the first half of 2007.

- **Louisiana State Lease 340 No. 2.** We commenced drilling the Louisiana State Lease 340 No. 2 exploratory well in 2001 and reached 18,704 feet. In January 2002, the well was perforated and flowed at various rates from 10 to 20 MMcfe/d, until a failure of the cement isolating the hydrocarbon-bearing sands caused water encroachment in the well. Remedial operations were unsuccessful in eliminating the water encroachment, and the well was temporarily abandoned. The No. 2 well is located approximately one mile from the Mound Point Offset wells discussed in "Farm-Out Arrangement with El Paso" above.

- **Nonproductive wells.** During 2006 and through February 2007 wells on the following prospects were evaluated as being nonproductive.

    - South Marsh Block 230 – "Elizabeth" prospect; total depth 19,950 feet; evaluated in January 2006;
    - West Cameron Block 95 – "Cabin Creek" prospect; total depth 18,688; evaluated in January 2006;
    - South Pass Block 26 – "Denali" prospect; total depth 17,442 feet;
    - Louisiana State Lease 18091 – "Long Point Deep" prospect; total depth 21,838 feet;
    - Vermilion Block 54 – total depth 14,669 feet;
    - Onshore Vermilion Parish – "Zigler Canal" prospect; objectives deeper than 13,500 feet determined to be nonproductive (shallower objectives resulted in discovery); and
    - Grand Isle Block 18 – "Marlin" prospect; total depth 16,000 feet; evaluated in January 2007.

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.

The properties were sold subject to a potential reversionary interest after "payout," which would occur if the purchaser received 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. During the first quarter of 2005, we reached an agreement with the purchaser to assign the 75 percent reversionary interest in Ship Shoal Block 296 to us effective February 1, 2005 (see "Producing Properties" above). Effective June 1, 2005, reversion of the interests in the other two properties occurred following payout. For additional information regarding this transaction, see "Capital Resources and Liquidity – Sales of Oil and Gas Properties" located in Items 7. and 7A., and Note 4 located elsewhere in this Form 10-K.

A joint venture, in which we owned 33.3 percent, acquired our Main Pass oil production facilities in December 2002. In December 2004, we acquired the 66.7 percent ownership interest in the joint venture not previously owned by us. For more information regarding these transactions see "Main Pass Oil Facilities" located in Items 7. and 7A. and Note 4 elsewhere in this Form 10-K.

Oil and Gas Reserves. The following table summarizes our estimated proved reserves of natural gas (in MMcf) and oil (in barrels) at December 31, 2006 based on a reserve report prepared by Ryder Scott using the criteria for developing estimates of proved reserves established by the SEC.

Gas		Oil	
Proved Developed	Proved Undeveloped	Proved Developed	Proved Undeveloped
34,949	6,253	5,526,457	245,843

The table above does not include any reserves (1) attributable to our potential reversionary interests in the JB Mountain and Mound Point discoveries, which are subject to a farm-out agreement with El Paso (see "Farm-Out Arrangement with El Paso" above) or (2) associated with our potential JB Mountain Deep discovery, which as of December 31, 2006 was considered unevaluated pending further evaluation which will occur following the results of the testing and evaluation of the Blueberry Hill well at Louisiana State Lease 340 (see "Discoveries and Development Activities" above). The table above includes proved developed reserves associated with the West Cameron Block 43 field (1,129 MMcf of natural gas and 46,395 barrels of oil) that we currently believe will not be recovered (see "Discoveries and Development Activities" above.

Because many of our properties are recent discoveries, they have little or no production history. Estimates of proved reserves for wells with little or no production history are less reliable than those based on a long production history. Subsequent evaluation of the properties may result in variations in estimates of proved reserves, which may be substantial. We anticipate that we will require additional capital to develop and produce our proved undeveloped reserves as well as our recent discoveries and any future discoveries. For additional information regarding our estimated proved reserves, see Note 12 and Item 1A. "Risk Factors" located elsewhere in this Form 10-K.

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, 2006. 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, 2006 for each property. The weighted average of these prices for all our properties with proved reserves was $53.56 per barrel of oil and $6.08 per Mcf for natural gas. The oil realization reflects the lower market value associated with the sour crude oil reserves produced at Main Pass, whose year-end 2006 price was $51.77 per barrel.

	Proved Developed	Proved Undeveloped	Total Proved
		(in thousands)	
Estimated undiscounted future net cash flows before income taxes	$ 277,864[a]	$ 37,151	$ 315,015
Present value of estimated future net cash flows before income taxes	$ 242,050[a]	$ 28,495	$ 270,545

a. Includes $7.9 million (undiscounted) and $6.9 million (present value) of future estimated cash flows associated with the West Cameron Block 43 field that we currently believe will not be recovered.

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 Item 1A. "Risk Factors" elsewhere in this Form 10-K.

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 natural 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,		
	2006	2005	2004
Net natural gas production (Mcf)	14,545,600	7,938,000	1,978,500
Net crude oil and condensate production, excluding Main Pass (Bbls)[a]	779,000	387,100	84,800
Net crude oil production from Main Pass (Bbls)[b]	775,500	463,000	-
Sales prices:			
Natural gas (per Mcf)	$ 7.05	$ 9.24	$ 6.08
Crude oil and condensate, including Main Pass (per Bbl)[c]	60.55	53.82	39.83
Production (lifting) costs: [d]			
Per barrel for Main Pass [e]	$35.76	$41.46	-
Per Mcfe for other properties[f]	1.34	1.06	$ 2.64

a. The amount during 2006 includes approximately 178,700 equivalent barrels of oil and condensate associated with $9.6 million of plant product revenues received for the value of such products recovered from the processing of our natural gas production. Our oil and condensate production includes 106,700 and 22,900 equivalent barrels of oil ($5.0 million and $0.6 million of revenues) associated with plant products during 2005 and 2004, respectively.
b. We sold our interests in the oil producing assets at Main Pass to a joint venture in December 2002. We acquired the ownership interest in the joint venture that we previously did not own on December 27, 2004. Production from Main Pass was shut in for a substantial portion of 2005 (see "Oil and Gas - Producing Properties" above).
c. Realization does not include the effect of the plant product revenues discussed in (a) above.
d. Production costs exclude all depletion, depreciation and amortization expense. 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.
e. Production costs for Main Pass included approximately $3.6 million, $4.68 per barrel in 2006 and $3.9 million, $8.31 per barrel in 2005, of estimated repair costs for damages sustained during Hurricane Katrina. The per barrel lifting cost during 2005 reflects the field being shut-in for substantial periods while still continuing to incur a significant level of the field's fixed production costs.
f. Production costs were converted to a Mcf equivalent on the basis of one barrel of oil being equivalent to six Mcf of natural gas. Production costs included workover expenses totaling $4.5 million or $0.23 per Mcfe in 2006, $1.2 million or $0.13 per Mcfe in 2005 and $0.6 million or $0.26 per Mcfe in 2004. Our production costs during 2004 include approximately $0.4 million or $0.18 per Mcfe of non-recurring costs associated with our acquisition of the Main Pass joint venture in December 2004.

Acreage. The following table shows the oil and gas acreage in which we held interests as of December 31, 2006. The table does not include approximately 157,000 gross acres associated with farm-in arrangements and the approximate 13,000 gross acres associated with the El Paso farm-out arrangement. Under our farm-in agreements, we will acquire ownership interests in this acreage when we, or others on our behalf, drill wells that are capable of producing reserves and commit to developing such wells. In January 2006 we negotiated a farm-out transaction that resulted in our obtaining

exploration rights to over 100,000 gross acres in southern Louisiana and on the Gulf of Mexico shelf (see "Oil and Gas Properties" above). For more information regarding our acreage position see Note 2.

	Developed		Undeveloped	
	Gross Acres	Net Acres	Gross Acres	Net Acres
Offshore (federal waters)	62,562	25,315	60,685	31,047
Onshore Louisiana and Texas	8,232	3,231	70,414	29,358
Total at December 31, 2006	70,794	28,546	131,099	60,405

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. For purposes of this table "productive wells" are defined as wells producing hydrocarbons or wells "capable of production." A well is considered successful or productive if the well encounters commercial quantities of hydrocarbons. This would include wells that have been suspended pending completion. A well is considered to be dry when we decide to permanently abandon the well. Multiple wells drilled from the same wellbore (i.e. sidetrack wells) count as one well in the table. For the year ending December 31, 2004, we had three exploratory wells, Dawson Deep, Minuteman and Hurricane No. 1, that had multiple wells drilled from one wellbore. All three of these wells were eventually determined to be productive wells (see "Discoveries and Development Activities" above). "Net wells" for the purposes of this table are defined to mean wells at our net revenue interest.

	2006		2005		2004	
	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Productive	6	2.375	4	1.426	4	1.394
Dry	4	1.185 [a]	6	2.021 [b]	5	1.413
In-progress	4	1.808	5	1.728	3	0.920
Total	14	5.368	15	5.625	12	3.727
Development						
Productive	7	2.613	2	0.667	-	-
Dry	-	-	-	-	-	-
In-progress	2	0.854 [c]	5	1.904 [c]	2	0.854 [c]
Total	9	3.467	7	2.571	2	0.854

a. Includes the exploratory well at Grand Isle Block 18 (0.26 net) that was determined to be nonproductive in early January 2007.
b. Includes the exploratory wells at South Marsh Island Block 230 (0.25 net) and West Cameron Block 95 (0.50 net) that were determined to be non-productive in early January 2006.
c. Includes the program's 0.304 net interest in the Mound Point Offset No. 2 well and 0.550 net interest in the JB Mountain No. 3, which have been temporarily abandoned.

The following table shows our interest in productive oil and natural gas wells as of December 31, 2006. For purposes of this table "productive wells" are defined as wells producing hydrocarbons and wells "capable of production" (for example wells waiting for pipeline connections or wells waiting to be connected to currently installed production facilities). This table does not include exploratory and development wells which have located commercial quantities of oil and natural gas but which are not capable of commercial production without installation of production facilities or wells that are shut-in and require a recompletion or workover to resume production. "Net wells" for the purposes of this table are defined to mean wells at our net revenue interest.

	Gas		Oil	
	Gross	Net	Gross	Net
Offshore	19	5.406	16	11.100
Onshore	8	2.287	-	-
Total	27	7.693	16	11.100

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 market prices.

MAIN PASS ENERGY HUB™ PROJECT

We have completed preliminary engineering for the development of the MPEH™ project. In February 2004, pursuant to the requirements of the U.S. Deepwater Port Act, we filed an application with the U.S. Coast Guard (Coast Guard) and the Maritime Administration (MARAD) requesting a license to develop an LNG receiving terminal located at our Main Pass facilities located offshore in the Gulf of Mexico, 38 miles east of Venice, Louisiana.

In March 2006 the Coast Guard and MARAD issued the Final Environmental Impact Study (EIS) for the MPEH™ project, which evaluated potential impacts associated with MPEH™. The EIS concluded that the environmental impacts associated with the construction and operation of MPEH™ would be expected to result in minor long-term adverse impacts. The EIS assessed the impact to fisheries of using an open rack vaporizer (ORV) alternative for the project and indicated this system would have "direct, adverse, minor impacts on biological resources." Despite the conclusions in the Final EIS supporting the MPEH™ application with ORV technology, on May 5, 2006, the Louisiana Governor vetoed our open-loop permit application. Following this action, we filed an amended application with the Coast Guard and MARAD requesting a license to develop an LNG receiving terminal using Closed Loop technology.

In September 2006, the Coast Guard and MARAD published the Environmental Assessment (EA) and Draft Finding of No Significant Impact for the MPEH™ project's LNG license application. Public hearings were held in October 2006 on the EA with no opposition. In January 2007, MARAD approved our license application for the MPEH™ project. MARAD concluded in its Record of Decision that construction and operations of MPEH™ deepwater port will be in the national interest and consistent with national security and other national policy goals and objectives, including energy sufficiency and environmental quality. MARAD also concluded that MPEH™ will fill a vital role in meeting national energy requirements for many years to come and that the port's offshore deepwater location will help reduce congestion and enhance safety in receiving LNG cargoes to the U.S.

MARAD's approval and issuance of the Deepwater Port license for MPEH™ is subject to various terms, criteria and conditions contained in its Record of Decision, including demonstration of financial responsibility, compliance with applicable laws and regulations, environmental monitoring and other customary conditions.

We are in discussions with potential LNG suppliers as well as natural gas marketers and consumers in the United States to develop commercial arrangements for the facilities. Prior to commencing construction of the facilities, we expect to enter into commercial arrangements that would enable us to finance the construction costs of the project as further discussed below.

The proposed terminal would be capable of regasifying LNG at a rate of 1 Bcf per day and is being designed to accommodate potential future expansions. The initial capital cost for the terminal facilities, based on preliminary engineering completed in 2003, was estimated at $440 million. We are seeking a permit for a facility with capacity up to 1.6 Bcf per day, which would add approximately $100 million to the preliminary estimated capital cost. In addition, the incorporation of Closed Loop technology is expected to result in a modest increase to our capital cost estimates for the facility. Following completion of front-end engineering and design for the project we expect to revise our preliminary capital cost estimates. The capital cost revisions will also incorporate any design modifications resulting from our commercial discussions and the increase in steel and other input costs since the 2003 estimates; accordingly, the cost of the project is expected to be significantly higher than the 2003 estimate. The use of Closed Loop technology will require our facility to consume approximately 1 percent more natural gas than would have been required with ORV technology.

The license application incorporates opportunities to develop substantial undersea cavern storage for natural gas in the 2-mile diameter salt dome located at the site and to construct pipeline interconnects to the U.S. pipeline distribution system, including a new 93-mile, 36-inch pipeline to Coden,

Alabama. This would provide 28 Bcf of initial cavern storage capacity and aggregate peak deliverability from the proposed terminal, including deliveries from storage, of up to 2.5 Bcf per day. The cost for these potential investments (which could be owned or financed by third parties) in pipelines and storage, based on preliminary engineering completed in 2003, was estimated to be $450 million. These cost estimates are also expected to be revised, and because of the factors noted above, the cost of the project is expected to be significantly higher than the 2003 estimates.

We believe that a natural gas terminal at Main Pass has numerous potential advantages over other LNG sites including:

- Offshore unloading provides savings compared with land-based facilities.
  - Remote offshore location near major shipping lanes avoids port congestion and offers shipping logistical advantages; and
  - Water depth of 210 feet allows access to the largest LNG carriers.

- Eastern Gulf of Mexico location offers a premium price to Henry Hub.
  - Dedicated off-take header will deliver to 8 major interstate pipeline systems; and
  - Onsite gas conditioning will allow receipt of a wide range of LNG Btu contents.

- Seasonal arbitrage opportunities through onsite gas cavern storage offer significant added value.
  - Extensive infrastructure allows future expansion;
  - Existing platforms over a large salt dome provide extensive cavern storage capacity; and
  - MPEH™ is the only facility in the United States combining LNG regas, gas conditioning, and onsite cavern storage.

As discussed in "Main Pass Oil Facilities" and "Discontinued Operations – Sulphur Reclamation Obligations" in Items 7. and 7A. and Notes 3, 4 and 11 located elsewhere in this Form 10-K, two entities have separate options to participate as passive equity investors for up to an aggregate 25 percent of our equity interest in the MPEH™ project. Future financing arrangements may also reduce our equity interest in the project.

DISCONTINUED SULPHUR OPERATIONS

Background. Until mid-2000, our sulphur business consisted of two principal operations, sulphur services and sulphur mining. Our sulphur services involved two principal components, the purchase and resale of recovered sulphur and sulphur transportation and terminaling 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, we ceased production from the Main Pass mine in August 2000 and then initiated a plan to sell our sulphur services assets.

Sale of Sulphur Assets. In June 2002, we sold our sulphur transportation and terminaling assets to Gulf Sulphur Services Ltd, LLP (GSS). We also agreed to indemnification obligations with respect to the sulphur assets sold to this joint venture, including certain environmental issues and liabilities relating to historical sulphur operations engaged in by us and our predecessor companies. In addition, we agreed to assume and indemnify IMC Global Inc., (now a subsidiary of Mosaic Company) one of the joint venture owners of GSS, against certain potential 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 Item 1A. "Risk Factors" below.

Sulphur Assets. Our primary remaining sulphur asset is our Port Sulphur, Louisiana facility, which is a combined liquid storage tank farm and stockpile area. The Port Sulphur terminal is currently inactive because it primarily served the Main Pass sulphur mine, which ceased operations in August 2000. The remaining facilities at Port Sulphur were damaged by Hurricane Katrina in August 2005 and Hurricane Rita in September 2005. Aggregate estimated closure costs for Port Sulphur approximate $12.1 million and we are pursuing accelerated closure alternatives under our reclamation plans for these facilities. Insurance recovery associated with claims from the hurricanes will partially mitigate these costs.

Sulphur Reclamation Obligations. We must restore our sulphur mines and related facilities to a condition that complies with environmental and other regulations. For financial information about our

estimated future reclamation costs, including those relating to Main Pass and the transactions with Offshore Specialty Fabricators Inc. (OSFI), see "Discontinued Operations" and "Environmental" in Items 7. and 7A. and Note 7 elsewhere in this Form 10-K.

Our Freeport Energy subsidiary has responsibility for environmental liabilities associated with the prior operations of its predecessors, including two previously producing sulphur mines, Caminada and Grand Ecaille. The Caminada reclamation work was performed during 2002. The 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.

REGULATION

General. Our exploration, development and production activities are subject to federal, state and local laws and regulations governing exploration, development, production, environmental matters, occupational health and safety, taxes, labor standards and other matters. All material licenses, permits and other authorizations currently required for our operations have been obtained or timely applied for. Compliance is often burdensome, and failure to comply carries substantial penalties. The regulatory burden on the oil and gas industry increases the cost of doing business and consequently affects profitability. See Item 1A. "Risk Factors" below.

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

Federal leases. At December 31, 2006, we had interests in 29 offshore leases located in federal waters on the Gulf of Mexico's outer continental shelf. Federal offshore leases are administered by the MMS. These leases were issued through competitive bidding, contain relatively standard terms and require compliance with detailed MMS regulations and the Outer Continental Shelf Lands Act, which are subject to interpretation and change by the MMS. Lessees must obtain MMS approval for exploration, development and production plans prior to the commencement of offshore operations. In addition, approvals and permits are required from other agencies such as the U.S. Coast Guard, the Army Corps of Engineers and the Environmental Protection Agency. The MMS has promulgated regulations requiring offshore production facilities and pipelines located on the outer continental shelf to meet stringent engineering and construction specifications, and has proposed and/or promulgated additional safety-related regulations concerning the design and operating procedures of these facilities and pipelines. MMS regulations also restrict the flaring or venting of natural gas and 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 fixed drilling and 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. We are meeting the supplemental bonding requirements of the MMS by providing financial assurances from MOXY. We and our subsidiaries' ongoing compliance with applicable MMS requirements will be subject to meeting certain financial and other criteria. Under some circumstances, the MMS could require any of our operations on federal leases to be suspended or terminated. Any suspension or termination of our operations could have a material adverse affect on our financial condition and results of operations.

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

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

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

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

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

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

The Oil Pollution Act also requires a responsible party to submit proof of its financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill.

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

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

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

EMPLOYEES

At December 31, 2006, we had 37 employees located at our New Orleans, Louisiana headquarters, who are primarily devoted to managerial, 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 (FM Services) pursuant to a services agreement. FM Services is a wholly owned subsidiary of Freeport-McMoRan Copper & Gold Inc. We may terminate the services agreement at any time upon 90 days notice. For the year ended December 31, 2006, we incurred $5.2 million of costs under the services agreement compared with $5.3 million in 2005 and $4.0 million in 2004. Our Co-Chairmen of our Board did not receive cash compensation during the three years ended December 31, 2006 (Note 8).

We also use contract personnel to perform various professional and technical services, including but not limited to drilling, 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 our oil and gas operations.

GLOSSARY

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

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

Bcf. Billion cubic feet.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

MMS. The U.S. Minerals Management Service.

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

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

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

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

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

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

Pay. Reservoir rock containing oil or gas.

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

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

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

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

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

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

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

Sands. Sandstone or other sedimentary rocks.

SEC. Securities and Exchange Commission.

Sour. High sulphur content.

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

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

Item 1A. 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 plans, our exploration and development plans and the potential development of the MPEH™ project; our ability to satisfy the MMS reclamation obligations with respect to Main Pass and our environmental obligations; drilling potential and results; anticipated flow rates of producing wells; anticipated initial flow rates of new wells; reserve estimates and depletion rates; general economic and business conditions; risks and hazards inherent in the production of oil and natural gas; demand and potential demand for oil and natural gas; trends in oil and natural gas prices; amounts and timing of capital expenditures and reclamation costs; and our ability to obtain necessary permits for new operations.

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

Factors Relating to Financial Matters

We will require additional capital to fund our future drilling activities and to pursue development of the MPEH™. If we fail to obtain additional capital, we may not be able to continue our operations or develop MPEH™.

Historically, we have funded our operations and capital expenditures through:

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

In the near-term, we plan to continue to pursue the drilling of our exploration prospects. We anticipate participating in the drilling of 8-10 exploratory wells in 2007. We anticipate that our capital expenditures during 2007 will approximate $150 million, which could increase with drilling successes. In addition, we may have future funding requirements under the El Paso program, if and when interests in those properties revert to us. We are also continuing our efforts to develop the MPEH™ project at our former sulphur mining facilities at Main Pass. Although we intend to fund our near-term expenditures with available cash, operating cash flows and borrowings under our revolving credit facility and term loan, we may need to raise additional capital through future equity or debt transactions. If we fail to obtain additional capital, we may not be able to continue our operations or develop the MPEH™ project.

Our future revenues will be reduced as a result of agreements that we have entered into and may enter into in the future with third parties.

We have entered into agreements with third parties in order to fund the exploration and development of certain of our properties. These agreements will reduce our future revenues. For example, we have entered into a farm-out agreement with El Paso to fund the exploration and

development for four of our prospects, two of which resulted in discoveries requiring further delineation and two of which were nonproductive. We have also participated in a multi-year exploration venture agreement with a private exploration and production company, who generally participated for 50 percent of our interest, paid 50 percent of our costs and assumed 50 percent of our obligations with respect to our prospects in which it elected to participate, except for the Dawson Deep prospect at Garden Banks Block 625 where our exploration partner participates for 40 percent of our interests, has assumed 40 percent of our obligations and pays 40 percent of our costs.

We also entered into an exploration agreement with Plains in the fourth quarter of 2006, where Plains agreed to participate in up to nine of our exploration prospects for approximately 55 to 60 percent of our initial ownership interests in the prospects. Subsequent elections may increase Plains' participation in certain of these prospects. We may also seek to enter into additional farm-out or other arrangements with other companies, but cannot assure you that we will succeed in doing so. Such arrangements would reduce our share of future revenues associated with our exploration prospects and will defer the realization of the value of our interest in the prospects until specified production quantities have been achieved as in the case of the El Paso farm-out arrangement, or specified net production proceeds have been received for the benefit of the other party. Consequently, even if exploration and development of the prospects is successful, we cannot assure you that such exploration and development will result in an increase in our revenues or our proved oil and gas reserves or when such increases 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 may continue to do so in the future. Our failure to achieve profitability in the future could adversely affect the trading price of our common stock and our other securities and our ability to raise additional capital.

Our continuing operations, which include start-up costs for the MPEH™, incurred losses of $44.7 million in 2006, $31.5 million in 2005, $52.0 million in 2004 and $41.8 million in 2003 and earned income of $18.5 million in 2002 (which included $44.1 million in gains on the disposition of oil and gas property interests). No assurance can be given that we will achieve profitability or positive cash flows from our operations in the future. Our failure to achieve profitability in the future could adversely affect the trading price of our common stock, our other securities and our ability to raise additional capital.

We are responsible for reclamation, environmental and other obligations relating to our former sulphur operations, including Main Pass and Port Sulphur.

In December 1997, we assumed responsibility for potential liabilities, including environmental liabilities, associated with the prior conduct of the businesses of our predecessors. Among these are potential liabilities arising from sulphur mines that were depleted and closed in the past in accordance with environmental laws in effect at the time, particularly in coastal or marshland areas that have experienced subsidence or erosion that has exposed previously buried pipelines and equipment. New laws or actions by governmental agencies calling for additional reclamation action on those closed operations could result in significant additional reclamation costs for us. We could also be subject to potential liability for personal injury or property damage relating to wellheads and other materials at closed mines in coastal areas that have become exposed through coastal erosion. As of December 31, 2006, we had accrued $9.9 million relating to reclamation liabilities with respect to our discontinued Main Pass sulphur operations (we have prepaid $2.6 million of this amount as of December 31, 2006), and $13.2 million relating to reclamation liabilities with respect to our other discontinued sulphur operations, including $12.1 million for the Port Sulphur facilities, for which we are pursuing various accelerated closure alternatives following damages sustained by the facilities from Hurricanes Katrina and Rita in 2005. We cannot assure you that actual reclamation costs ultimately incurred will not exceed our current and future accruals for reclamation costs, that we will have the cash to fund these costs when incurred or that we will be able to satisfy applicable bonding requirements.

We are subject to indemnification obligations with respect to the sulphur transportation and terminaling assets that we sold in June 2002, including sulphur and oil and gas obligations arising under environmental laws.

We are subject to indemnification obligations with respect to the sulphur operations previously engaged in by us and our predecessor companies. In addition, we assumed, and agreed to indemnify IMC Global Inc. (now a subsidiary of the Mosaic Company) from certain potential obligations, including environmental obligations relating to historical oil and gas operations conducted by the Freeport-McMoRan companies prior to the 1997 merger of Freeport-McMoRan Inc. and IMC Global. Our liabilities with respect to those obligations could adversely affect our operations and liquidity.

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 natural gas reserves. We cannot assure you that we will be able to do so profitably. Moreover, because our ownership interests in prospects subject to farm-out or other exploration arrangements 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 generate revenues to us and increase our proved oil and gas reserves. We cannot assure you that any of our exploration or farm-out arrangements will result in an increase in our revenues or 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 natural gas exploration and development activities 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 the related 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 natural gas is present or economically producible. The cost of drilling, completing and operating a well is often uncertain, especially when drilling offshore and when drilling deep wells, 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 natural 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 the related drilling, completion and operating costs.

In addition, we plan to conduct most of our near-term exploration, development and production operations on the deep shelf of the Gulf of Mexico, an area that has had limited historical drilling activity due, in part, to its geologic complexity. There are additional risks associated with deep shelf drilling (versus traditional shelf drilling) that could result in substantial losses. Deeper targets are more difficult to detect with traditional seismic processing. Moreover, the expense of drilling deep shelf wells and the risk of mechanical failure is significantly higher because of the additional depth and adverse conditions such as high temperature and pressure. Our exploratory wells involve significant expenditures (typically ranging between $10-$20 million) to ascertain whether or not they discover commercially recoverable oil and natural gas reserves; however, our experience suggests that exploratory costs can exceed $30

million per deep shelf well drilled. Accordingly, we cannot assure you that our oil and natural gas exploration activities, either on the deep shelf or elsewhere, will be commercially successful.

The future results of our oil and natural gas business are difficult to forecast, primarily because the results of our exploration strategy are unpredictable.

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

The marketability of our production depends mostly upon the availability, proximity and capacity of natural gas gathering systems, pipelines and processing facilities.

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

Because our reserves and production are concentrated in a small number of offshore properties, production problems or significant changes in reserve estimates related to any property could have a material impact on our business.

At December 31, 2006, our production was associated with 11 producing properties in the shallow waters of the Gulf of Mexico, five properties located onshore in Louisiana and one located in the deep water of the Gulf of Mexico. Additionally, these properties, including Main Pass Block 299 represent a substantial portion of our year-end 2006 estimated proved reserves. If mechanical problems, depletion, storms or other events reduced a substantial portion of this production, our cash flows would be adversely affected. If the actual reserves associated with our fields are less than our estimated reserves, our results of operations and financial condition could be adversely affected.

We are vulnerable to risks associated with the Gulf of Mexico because we currently explore and produce exclusively in that area.

Our strategy of concentrating on the Gulf of Mexico makes us more vulnerable to the risks associated with operating in that area than our competitors with more geographically diverse operations. These risks include:

- hurricanes, which are common in the Gulf of Mexico during certain times of the year, and other adverse weather conditions;
- difficulties securing oil field services; and
- compliance with existing and future regulations.

In addition, production from the Gulf of Mexico shelf generally declines more rapidly than in other producing regions of the world because reservoirs in the Gulf of Mexico shelf are generally sandstone reservoirs characterized by high porosity and high permeability that results in an accelerated recovery of production in a relatively short period of time, with a generally more rapid decline near the end of the life of the reservoir. 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 relatively rapid rate.

The amount of oil and natural 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 natural 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 natural 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 natural gas prices, future operating and development costs, workover, remediation and abandonment costs, and severance and excise taxes; and
- the assumed effects of government regulation.

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

You should not construe the estimated present values of future net cash flows from proved oil and natural gas reserves as the current market value of our estimated proved oil and natural 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, 2006, without any adjustment to normalize those prices and costs based on variations over time either before or after that date. Future prices and costs may be materially higher or lower. Future net cash flows also will be affected by such factors as:

- the actual amount and timing of production;
- changes in consumption by gas purchasers; and
- changes in governmental regulations and taxation.

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

Financial difficulties encountered by our partners or third-party operators could adversely affect the exploration and development of our prospects.

We have a farm-out agreement with El Paso to fund the exploration and development costs of our JB Mountain and Mound Point prospects. We also have entered into exploration agreements with industry participants covering the future costs of exploring and developing our exploration acreage. In addition, other companies operate some of the other properties in which we have an ownership interest. Liquidity and cash flow problems encountered by our partners or the co-owners of our properties may prevent or delay the drilling of a well or the development of a project.

In addition, our farm-out partners and working interest co-owners may be unwilling or unable to pay their share of the costs of projects as they become due. In the case of a farm-out partner, we would have to find a new farm-out partner or obtain alternative funding in order to complete the exploration and development of the prospects subject to the farm-out agreement. In the case of a working interest owner,

we could be required to pay the working interest owner's share of the project costs. We cannot assure you that we would be able to obtain the capital necessary to fund either of these contingencies or that we would be able to find a new farm-out partner.

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 natural gas.

In recent years, oil and natural 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 natural gas prices would have a material adverse effect on our profitability, financial condition and operations and on the trading prices of our securities.

If oil and natural gas prices decrease or our exploration efforts are unsuccessful, we may be required to write down the capitalized cost of individual oil and natural gas properties.

A writedown of the capitalized cost of individual oil and natural gas properties could occur when oil and natural gas prices are low or if we have substantial downward adjustments to our estimated proved oil and gas reserves, increases in our estimates of development costs or nonproductive exploratory drilling results. A writedown could adversely affect the trading prices of our securities.

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

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

We assess our properties for impairment periodically, based on future estimates of proved and risk-adjusted probable reserves, oil and natural gas prices, production rates and operating, development and reclamation costs based on operating budget forecasts. Once incurred, an impairment charge cannot be reversed at a later date even if we experience increases in the price of oil or natural gas, or both, or increases in the amount of our estimated proved reserves.

Shortages of supplies, equipment and personnel may adversely affect our operations.

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

The loss of key personnel could adversely affect our ability to operate.

We depend, and will continue to depend in the foreseeable future, on the services of our senior officers and other key employees with extensive experience and expertise in:

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

Our ability to retain our senior officers and other key employees, none of whom are subject to an employment agreement with us, is important to our future success and growth. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on our business.

The oil and natural 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 natural 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 at commercially reasonable costs.

Our operations are subject to the hazards and risks inherent in drilling for, producing and transporting oil and natural 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, lost production, remediation and clean-up costs, and other environmental damages. 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;

- 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.

As a result, substantial liabilities to third parties or governmental entities may be incurred, which could have a material adverse effect on our financial condition and results of operations.

We have historically maintained insurance coverage for our operations, including liability, property damage, business interruption, limited coverage for sudden and accidental environmental damages, and other insurance coverages. Any insurance coverage we elect to purchase will not provide protection against all potential liabilities incident to the ordinary conduct of our business. Moreover, any insurance coverage we maintain will be subject to coverage limits, deductibles and other conditions. In addition, our insurance will not cover damages caused by war or environmental damages that occur over time. The occurrence of an event that is not covered by insurance would adversely affect our financial condition and results of operations.

Hedging our production may result in losses.

We currently have no hedging agreements in place. However, we may in the future enter into arrangements to reduce our exposure to fluctuations in the market prices of oil and natural gas. We may enter into oil and natural 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 natural gas. Further, if we do not engage in hedging, we may be more adversely affected by changes in oil and natural gas prices than our competitors who engage in hedging.

Compliance with environmental and other government regulations could be costly and could negatively affect production.

Our operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may:

- require the acquisition of a permit before drilling commences;

- restrict the types, quantities and concentration of various substances that can be released into the environment from drilling and production activities;

- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas;

- require remedial measures to address or mitigate pollution from former operations, such as plugging abandoned wells;

- impose substantial liabilities for pollution resulting from our operations; and

- require capital expenditures for pollution control equipment.

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

Our operations could result in liability for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. We could also be liable for environmental damages caused by previous property owners. As a result, substantial liabilities to third parties or governmental entities may be incurred, which could have a material adverse effect on our financial condition and results of operations. We could also be held liable for any and all consequences arising out of human exposure to hazardous substances, including without limitation, asbestos-containing materials, or other environmental damage which liability could be substantial.

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

Factors Relating to the Potential Main Pass Energy Hub™ Project

Even if we obtain the approvals and permits from regulatory agencies necessary to use our Main Pass facilities as an LNG terminal, we may not be able to obtain the necessary financing to complete the project.

Even if we obtain the approvals and permits from regulatory agencies, the conversion of our Main Pass sulphur facilities to an LNG receipt and processing terminal would require significant project-based financing for the associated engineering, environmental, regulatory, construction and legal costs. We may not be able to obtain such financing at an acceptable cost, or at all, which would have an adverse effect on our ability to pursue alternative uses of the Main Pass facilities. Financing arrangements for the project may also reduce our economic interest in, and control of, the project.

Our interest in the proposed LNG terminal project will be reduced if either or both K1 USA or OSFI exercises its option to acquire a passive equity interest in our Main Pass Energy Hub™ project, and may be further reduced by any financing arrangements that may be entered into with respect to the project.

K1 USA Ventures, Inc. and K1 USA Energy Production Corporation ("K1 USA"), subsidiaries of k1, have the option, exercisable upon the closing of any project financing arrangements, to acquire up to 15 percent of our equity interest in the MPEH™ project by agreeing prospectively to fund up to 15 percent of our future contributions to the project. In connection with our settlement of litigation with Offshore Specialty Fabricators Inc. (OSFI), OSFI has the right to participate as a passive equity investor for up to 10 percent of our equity interest in the MPEH™ project on a basis parallel with our agreement with K1 USA. If either option is exercised, our economic interest in MPEH™ project would be reduced. Financing arrangements for the project may also reduce our economic interest in, and control of, the project.

Failure of LNG to compete successfully in the United States natural gas market could have a detrimental effect on our ability to pursue alternative uses of our Main Pass facilities.

Because the United States historically has had an abundant supply of domestic natural gas, LNG has not been a major energy source. In addition to natural gas, LNG also competes with other sources of energy, including coal, oil, nuclear, hydroelectronic, wind, and solar energy. As a result, LNG may not become a competitive source of energy in the United States. The failure of LNG to become a competitive supply alternative to domestic natural gas and other energy alternatives may have a material adverse effect on our ability to use our Main Pass facilities as a terminal for LNG receipt and processing and natural gas storage and distribution.

We face competition in the LNG receipt and processing terminal business from competitors with greater resources and the potential for overcapacity in the LNG receipt and processing terminal marketplace.

Although there are only a limited number of LNG terminal facilities currently operating in North America, many companies are pursuing the development of infrastructure, both onshore and offshore, to serve the North American natural gas market. Some of these competitors have greater name recognition, larger staffs and greater financial, technical and marketing resources than we do. The superior resources that some of our competitors have available to deploy could allow them to surpass us in terms of the status of their proposed LNG receiving terminal development projects. Among other things, some of our

competitors may not have to rely on external financing. Industry analysts have predicted that if all of the proposed LNG receiving terminals in North America that have been announced by developers are actually built, there could be substantial excess capacity for such terminals in the future. Excess capacity would likely lead to decreased prices for such services. Because of the substantial likelihood that we will have significant debt service obligations, any such price decreases would impact us more severely than our competitors with greater financial resources.

If we were to develop an LNG terminal at our Main Pass facilities, fluctuations in energy prices or the supply of natural gas could be harmful to those operations.

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

Our proposed LNG terminal would be subject to significant operating hazards and uninsured risks, one or more of which may create significant liabilities for us.

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

The inability to import LNG into the United States due to, among other things, governmental regulation or political instability in countries that supply natural gas could materially adversely affect our business plans and results of operations.

In the event we complete and establish an LNG terminal at Main Pass, our business will be dependent upon the ability of our customers to import LNG supplies into the United States. Political instability in foreign countries that have supplies of natural gas or strained relations between such countries and the United States may impede the willingness or ability of LNG suppliers in such countries to export LNG to the United States. Such foreign suppliers may also be able to negotiate more favorable prices with other LNG customers around the world than with customers in the United States, thereby reducing the supply of LNG available to be imported into the United States market.

Other Factor

The U.S military intervention in Iraq, the terrorist attacks in the United States on September 11, 2001, and the potential for future terrorist acts have created economic, political and social uncertainties that could materially and adversely affect our business.

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

Item 1B. Unresolved Staff Comments

None

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.). In December 2005, we announced that we reached an agreement in principle with the plaintiffs to settle this class action litigation. In accordance with the terms of the settlement, we paid $17.5 million in cash into a settlement fund in March 2006, the plaintiffs have provided a complete release of all claims, and the Delaware litigation has been dismissed with prejudice. Our insurance carriers funded $5.1 million of our settlement costs.

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

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

None.

Executive Officers of the Registrant

Listed below are the names and ages, as of March 1, 2007, 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	68	Co-Chairman of the Board
Richard C. Adkerson	60	Co-Chairman of the Board
Glenn A. Kleinert	64	President and Chief Executive Officer
C. Howard Murrish	66	Executive Vice President
Nancy D. Parmelee	55	Senior Vice President, Chief Financial Officer and Secretary
Kathleen L. Quirk	43	Senior Vice President and Treasurer
John G. Amato	63	General Counsel

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

Richard C. Adkerson has served as our Co-Chairman of the Board since November 1998. He served as our President and Chief Executive Officer from November 1998 to February 2004. Mr. Adkerson has also served as a director of FCX since October 2006, Chief Executive Officer of FCX since December 2003, as President of FCX since April 1997 and as Chief Financial Officer from October 2000 until December 2003.

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

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

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

Kathleen L. Quirk has served as Senior Vice President and Treasurer of McMoRan since April 2002 and previously served as Vice President and Treasurer from January 2000 to April 2002. Ms. Quirk

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

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

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock is listed on the New York Stock Exchange (NYSE) under the symbol "MMR." Our Chief Executive Officer submitted the Annual CEO Certification to the NYSE as required under the NYSE Listed Company rules. The following table sets forth, for the period indicated, the range of high and low sales prices, as reported by the NYSE.

	2006		2005	
	High	Low	High	Low
First Quarter	$21.12	$16.77	$23.55	$16.00
Second Quarter	19.63	14.37	22.20	16.96
Third Quarter	19.42	16.60	20.69	16.85
Fourth Quarter	18.46	13.95	20.34	15.75

As of February 28, 2007 there were 7,861 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.

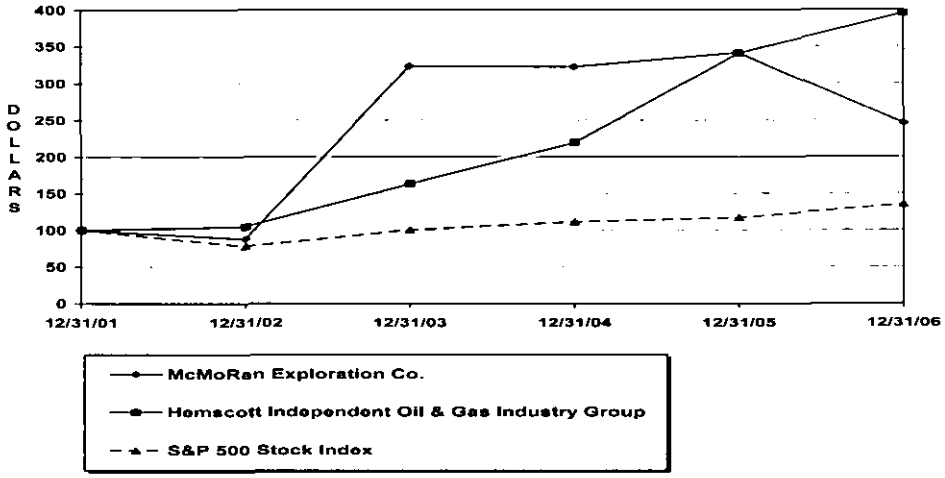
Issuer Purchases of Equity Securities

In 1999, our Board of Directors approved an open market share purchase program for up to 2.0 million shares of our common stock. In 2000, the Board of Directors authorized the purchase of up to an additional 0.5 million shares under the program. The program does not have an expiration date. No shares were purchased during the three years ending December 31, 2006. Approximately 0.3 million shares remain available for purchase under the program (Note 1).

Performance Graph

The following graph compares the change in the cumulative total stockholder return on our common stock with the cumulative total return of the Hemscott Independent Oil & Gas Industry Group and the S&P Stock Index from 2002 through 2006. This comparison assumes $100 invested on December 31, 2001 in (a) our common stock, (b) the Hemscott Independent Oil & Gas Industry Group, and (c) the S&P 500 Stock Index.

Comparison of Cumulative Total Return*
McMoRan Exploration Co., Hemscott Independent Oil & Gas Industry Group and S&P 500 Stock Index



	December 31,					
	2001	2002	2003	2004	2005	2006
McMoRan Exploration Co.	$100.00	$ 88.08	$ 323.83	$ 322.97	$ 341.45	$ 245.60
Hemscott Independent Oil & Gas Industry Group	100.00	104.71	163.33	219.43	340.60	395.82
S&P 500 Stock Index	100.00	77.90	100.25	111.15	116.61	135.03

* Total Return Assumes Reinvestment of Dividends

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, 2006. 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 Operation and Qualitative and Quantitative Disclosures About Market Risk" and Item 8. "Financial Statements and Supplementary Data." References to "Notes" refer to Notes to Consolidated Financial Statements located in Item 8. of this Form 10-K.

	2006	2005	2004	2003	2002
Financial Data	(Financial Data in thousands, except per share amounts)				
Years Ended December 31:					
Revenues [a]	$ 209,738	$ 130,127	$ 29,849	$ 17,284	$ 44,247
Exploration expenses	67,737	63,805	36,903	14,109	13,259
Start-up costs for Main Pass Energy Hub™ [b]	10,714	9,749	11,461	11,411	-
Exploration expense reimbursement [c]	(10,979)	-	-	-	-
Litigation settlement [d]	(446)	12,830	-	-	-
Insurance recovery [e]	(3,306)	(8,900)	(1,074)	-	-
Gain on sale of oil and gas properties [f]	-	-	-	-	44,141
Operating income (loss)	(32,567)	(22,373)	(43,940)	(38,947)	17,942
Income (loss) from continuing operations	(44,716)	(31,470)	(52,032)	(41,847)	18,544
Income (loss) from discontinued operations [g]	(2,938)	(8,242)	361	(11,233)	(503)
Cumulative effect of change in accounting principle	-	-	-	22,162[h]	-
Net income (loss) applicable to common stock	(49,269)	(41,332)	(53,313)	(32,656)	17,041
Diluted net income (loss) per share of common stock:					
Continuing operations	(1.66)	(1.35)	(2.85)	(2.62)	0.93[i]
Discontinued operations	(0.10)	(0.33)	0.02	(0.68)	(0.02)[i]
Cumulative effect of change in accounting principle	-	-	-	1.33	-
Diluted net income (loss) per share	$ (1.76)	$ (1.68)	$ (2.83)	$ (1.97)	$ 0.91[i]
Average common shares outstanding					
Basic	27,930	24,583	18,828	16,602	16,010
Diluted	27,930	24,583	18,828	16,602	19,879[k]
At December 31:					
Working capital (deficit)	$ (25,906)	$ 67,135	$ 175,889	$ 83,143	$ 5,077
Property, plant and equipment, net	282,582	192,397	97,262	26,185	37,895
Discontinued sulphur business assets	362	375	312	312	355
Total assets	408,677	407,636	383,920	169,280	72,448
Long-term debt	244,620[j]	270,000	270,000	130,000	-
Mandatorily redeemable convertible preferred stock	29,043	28,961	29,565	30,586	33,773
Stockholders' deficit	$ (68,443)[j]	$ (86,590)	$ (49,546)	$ (84,593)	$ (64,431)

a. Includes service revenues totaling $13.0 million in 2006, $12.0 million in 2005, $14.2 million in 2004, $1.2 million in 2003 and $0.5 million in 2002. The service revenues primarily reflect recognition of the

management fees received associated with our exploration venture activities (Note 2), oil processing fees and other third party management fees (Note 1).

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

c. Reflects $20.0 million received upon inception of exploration agreement in fourth quarter of 2006 (Note 2). We recorded $19.0 million of this payment as exploration expense reimbursement with the remainder as a reduction of property, plant and equipment, less an $8.0 million payment to our previous exploration venture partner for relinquishing certain of their exploration rights.

d. Reflects settlement of class action litigation case, net of insurance proceeds (Note 11).

e. Reflects proceeds received in connection with our hurricane-related insurance claims (see "Main Pass Oil Facilities" below and Note 4).

f. Includes sales of various oil and gas properties (Note 4).

g. Amounts in 2006 and 2005 include charges for modification of previously estimated reclamation plans for remaining facilities at Port Sulphur, Louisiana as a result of hurricane damages ($3.4 million in 2006 and $3.5 million in 2005). Amounts also include year-end reductions ($3.2 million in 2006, $3.5 million in 2005 and $5.2 million in 2004) in the contractual liability associated with postretirement benefit costs relating to certain retired former sulphur employees (Note 11). The amount for 2003 includes a $5.9 million estimated loss on the disposal of our remaining sulphur railcars, which were sold during 2004. The amount for 2002 includes a $5.0 million gain on completion of the Caminada sulphur mine reclamation activities, a $5.2 million gain to adjust the estimated reclamation cost for certain Main Pass sulphur structures and facilities and an aggregate $4.6 million loss on the disposal of sulphur transportation and terminaling assets.

h. Reflects implementation of Statement of Financial Accounting Standard No. 143 "*Accounting for Asset Retirement Obligations*" effective January 1, 2003 (Note 1).

i. Basic net income (loss) per share of common stock in 2002 totaled $1.06 per share, reflecting $1.09 per share from continuing operations and $(0.03) per share from discontinued operations.

j. In the first quarter of 2006, debt conversion transactions were completed that reduced long-term debt by $54.1 million and resulted in the issuance of approximately 3.6 million shares of McMoRan common stock (Note 5).

k. Includes the assumed conversion of McMoRan's 5% Convertible Preferred Stock into approximately 3.9 million shares (Note 6).

	2006	2005	2004	2003	2002
Operating Data					
Sales Volumes:					
Gas (thousand cubic feet, or Mcf)	14,545,600	7,938,000	1,978,500	2,011,100	5,851,300 [a]
Oil (barrels) [b]	1,379,300	716,400	61,900	107,600	1,126,600 [c]
Plant products (equivalent barrels) [d]	178,700	106,700	22,900	20,700	26,100
Average realization:					
Gas (per Mcf)	$ 7.05	$ 9.24	$ 6.08	$ 5.64	$ 3.00
Oil (per barrel)	60.55	53.82	39.83	30.76	22.28

a. Sales volumes associated with properties sold in February 2002 (Note 4) totaled 856,000 Mcf in 2002.

b. A joint venture, in which we held a 33.3 percent interest, acquired the Main Pass oil operations in December 2002. We acquired the interest in the joint venture not owned by us in December 2004. The Main Pass oil operations were shut-in for a substantial portion of 2005 resulting from damages sustained from hurricanes (see "Main Pass Oil Facilities" and Note 4). Oil sales from Main Pass totaled 779,000 barrels in 2006, 436,000 barrels in 2005, 4,200 barrels in 2003 and 1,001,900 barrels in 2002. Amounts during 2003 represent the sale of the remaining Main Pass product inventory from December 2002. Main Pass produces sour crude oil, which sells at a discount to other crude oils.

c. Sales volumes associated with properties sold in February 2002 totaled 18,500 barrels in 2002.

d. During 2006 revenues included $9.6 million of proceeds from plant products (ethane, propane, butane, etc.). Revenues from plant products totaled $5.0 million in 2005, $0.6 million in 2004, $0.8 million in 2003 and $0.9 million in 2002.

Items 7. and 7A. Management's Discussion and Analysis of Financial Condition and Results of Operation and Quantitative and Qualitative Disclosures About Market Risk

OVERVIEW

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

We engage in the exploration, development and production of oil and natural gas offshore in the Gulf of Mexico and onshore in the Gulf Coast region, with a focus on potentially significant hydrocarbons which we believe are contained in large, deep geologic structures often located beneath shallow reservoirs where significant reserves have been produced. We are also pursuing plans for the development of liquefied natural gas (LNG) facilities at the Main Pass Energy Hub™ (MPEH™) using our former sulphur mining facilities at Main Pass Block 299 (Main Pass) in the Gulf of Mexico. This proposed project includes the conversion of our former Main Pass sulphur facilities into a hub for the receipt and processing of LNG and the storage and distribution of natural gas. We were previously engaged in mining of sulphur at Main Pass until August 2000 and discontinued other sulphur business activities in June 2002.

Business Strategy

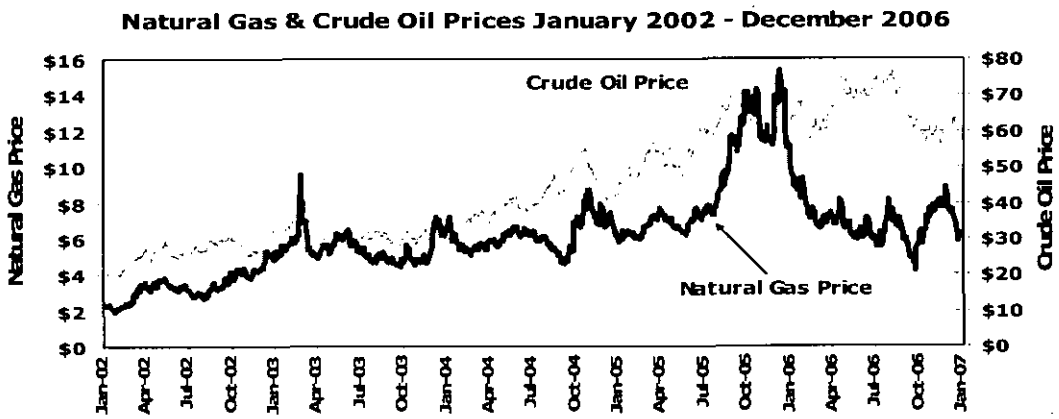
Our business strategy provides potential opportunities for our company to benefit from a positive U.S. natural gas market through an aggressive exploration drilling program in the Gulf of Mexico and Gulf Coast region and the establishment of an LNG receiving, processing, distribution and storage facility at Main Pass. We explore for natural gas in deep reservoirs in an area that is relatively under-explored and that involves significant drilling costs and relatively high exploration risks. We target exploration prospects that have the potential for large accumulations of hydrocarbons in shallow water depths and onshore where existing oil and natural gas production infrastructure generally allows discoveries to generate production and cash flow relatively quickly. Our near-term business strategy is to continue to pursue aggressively our oil and natural gas exploration and development activities and our plans for the MPEH™ project.

Implementing our strategy will require significant expenditures during 2007 and beyond. During 2006 we spent $252.4 million on capital-related projects primarily associated with our exploration activities and the subsequent development of our related discoveries. We expect to spend approximately $150 million on oil and gas capital projects during 2007. We expect to fund our near-term business plan by using cash flow from our operations, our existing unrestricted cash, including proceeds from the recently completed term loan transaction (see "Capital Resources and Liquidity – Senior Term Loan Agreement" below) and borrowings under our revolving credit facility. We will pursue additional debt or equity financing for our MPEH™ activities. The ultimate outcome of our efforts is subject to various uncertainties, many of which are beyond our control. For additional information on these and other risks see Item 1A. "Risk Factors" included in this Form 10-K.

North American Natural Gas Environment

North American natural gas prices declined significantly during 2006 from the record high prices of late 2005 (see chart below), as gas storage levels reached record highs. However, the market fundamentals for natural gas over the medium term are positive with projections of rising demand exceeding North American supply (discussed more below).

During 2006, the world oil market reflected conditions of high demand and tight supplies. However, after oil prices reached a high of almost $80 per barrel during the third quarter, oil prices declined because of market perception of decreased risk of supply disruptions associated with hurricanes and international supplies.



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

Industry experts project declines in natural gas production from traditional sources in the U.S. and Canada. Accordingly, industry experts project that, over the next two decades, non-traditional sources of natural gas, such as Alaska, the Canadian Arctic, the deep shelf, tight sands gas, shale gas, coal seam methane and imported LNG will provide a significantly larger share of the supply. We believe that we are well positioned to pursue two of these alternative supply sources, namely deep shelf production and LNG imports, by exploiting our deep shelf exploration acreage and developing the MPEH™ project.

LNG has historically represented a small source of natural gas to the U.S. market because of abundant domestic supplies of natural gas. Over the next several years, LNG imports are expected to grow as a result of declining domestic natural gas production. As a result, numerous new LNG regasification facilities have been proposed and several have obtained permits during the past two years. Development of LNG facilities often requires long lead times to secure regulatory and environmental permitting, as well as project financing.

We believe that MPEH™'s location offers numerous benefits to LNG suppliers and U.S. gas consumers and marketers. Its eastern Gulf of Mexico location would deliver to premium markets in Florida and on the East Coast. MPEH™'s deepwater location offers benefits to shippers who can avoid congested ports and waterways when delivering LNG. Additionally, offshore locations, such as the proposed MPEH™, could mitigate security and safety issues often faced by competing onshore facilities.

OPERATIONAL ACTIVITIES

Exploration Agreements

We and a private exploration and production company (exploration partner) entered into a joint commitment in 2004 to spend at least $500 million to pursue exploration prospects primarily in Deep Miocene formations on the shelf of the Gulf of Mexico and onshore in the Gulf Coast area. Spending commitments under the venture were met in 2006.

During the term of the exploration venture, we and our exploration partner generally shared equally in all future revenues and costs, including related overhead costs, associated with the exploration venture's activities, except for the Dawson Deep prospect at Garden Banks Block 625, where the exploration partner is participating in 40 percent of our interests. We and our private partner will continue to participate jointly in the exploration venture's 14 discoveries, as well as in those wells which have not yet been fully evaluated as discussed below. The exploration partner paid us $9.0 million of management fees in 2006, $7.0 million in 2005 and $12.0 million in 2004. We recognized these management fees as service revenue in the accompanying consolidated statements of operations. We will not receive any management fees for exploration venture services during 2007. We paid our exploration partner $8.0 million in the fourth quarter of 2006 for relinquishing its exploration rights to certain prospects in connection with our entering into a new exploration agreement with another third party (see below).

In the fourth quarter of 2006, we entered into an exploration agreement with Plains Exploration & Production Co. (Plains) whereby Plains will participate in up to nine of our exploration prospects for approximately 55 percent to 60 percent of our initial ownership interests in the prospects. Subsequent individual joint operating agreements may increase Plains' participation in certain prospects. Under the agreement, Plains paid us $20 million for these leasehold interests and related prospect costs. We reflected $19.0 million of this payment as operating income in the accompanying consolidated statements of operations within the caption titled "Reimbursement of exploration expense" and it is included within our operating cash flows in the accompanying consolidated statements of cash flow. The remaining $1.0 million was classified as a reduction of our basis in the specified nine prospects and is included within investing activities in the accompanying consolidated statements of cash flow.

Drilling Update

Since 2004, we have participated in 15 discoveries on the 29 prospects that have been drilled and fully evaluated. We have commenced production from 13 of these discoveries to date, and expect to bring on production from the recent discoveries in the near-term. We are in the process or testing and evaluating the Blueberry Hill well at Louisiana State Lease 340. The well has been perforated but production has not yet been established because of blockage above the perforated intervals. Additional operations to clear the blockage and complete testing of the well are expected in the near-term. Information obtained from the testing and evaluation of the Blueberry Hill well will be incorporated into the plan to evaluate the JB Mountain Deep well at South Marsh Island Block 224. At December 31, 2006, our investments in the Blueberry Hill and JB Mountain Deep prospects totaled $16.5 million and $29.5 million, respectively.

The first two prospects under the Plains agreement, Marlin at Grand Isle Block 18 and Hurricane Deep at South Marsh Island Block 217, commenced drilling in the fourth quarter of 2006. The Marlin well reached its total planned depth and was determined to be nonproductive resulting in a charge to exploration expense of $7.0 million for our net share of the costs incurred on the well through December 31, 2006. In the first quarter of 2007, we expect to record an approximate $1.1 million charge to exploration expense for our net share of the costs associated with the Marlin well incurred subsequent to December 31, 2006. A discovery was announced at the Hurricane Deep well in late February 2007. We commenced drilling the Cas exploratory well at South Timbalier Block 70 on January 30, 2007 and the Cottonwood Point exploratory well at Vermilion Block 31 on March 1, 2007. We expect to commence drilling the Mound Point South exploratory well at Louisiana State Lease 340 around the end of the first quarter of 2007.

In June 2005, we acquired oil and natural gas rights from El Paso Production Company, a subsidiary of El Paso Corporation (El Paso), covering six deep-gas exploration prospects on approximately 18,000 gross acres onshore and in state waters in Vermilion Parish, Louisiana. We and our private exploration partner paid El Paso approximately $3.6 million as partial recovery of prospect costs and will fund 100 percent of the drilling costs to casing point in up to six wells, representing the initial well at each prospect. At casing point of each well, El Paso can elect to participate for a 25 percent working interest, and we and our exploration partner would own a 75 percent working interest (37.5 percent each) and an approximate 54 percent net revenue interest (approximately 27 percent each). We have drilled four prospects on this acreage, all of which have resulted in discoveries (Long Point and Cane Ridge in 2005 and Liberty Canal and Zigler Canal in 2006).

In May 2002, we entered into an exploration arrangement with El Paso through a farm-out transaction covering four of our prospects. El Paso completed drilling initial exploratory wells at each of the four prospects, which resulted in two discoveries (JB Mountain and Mound Point). In 2004, El Paso relinquished to us its rights to all but 13,000 gross acres surrounding the JB Mountain and Mound Point Offset wells.

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

Acreage Position

Our exploration team has undertaken an intensive process to evaluate our substantial acreage position from a technical standpoint. This evaluation has identified over 20 prospects, including many deep gas exploration targets near existing production infrastructure. At December 31, 2006, we had rights to approximately 370,000 gross acres (approximately 132,000 acres net to our interest). We are

continuing to identify prospects to be drilled on our lease acreage and we are also actively pursuing opportunities to acquire additional acreage and prospects through farm-in or other arrangements. For more information regarding our acreage position see Note 2 and "Oil and Gas Operations – Acreage" in Items 1. and 2. "Business and Properties" of this Form 10-K.

Production Update

Our net production rates increased to an average of 65 MMcfe/d during 2006 compared with 36 MMcfe/d in 2005 and 7 MMcfe/d in 2004. During 2006 we initiated production from 14 additional wells, which are described at "Oil and Gas Operations – Discoveries and Development Activities" in Items 1. and 2. "Business and Properties" of this Form 10-K. Our first-quarter 2007 production rates are expected to average between 70-80 MMcfe per day, net to our interests, including 1,900 barrels of oil per day (11 MMcfe/d) from Main Pass.

MAIN PASS ENERGY HUB™ PROJECT

We are pursuing aggressively plans for the development of the MPEH™ project. For a description of the project, including preliminary capital expenditure estimates, see "Main Pass Energy Hub™ Project" located in Items 1. and 2. "Business and Properties" of this Form 10-K. We have completed preliminary engineering for the project. In February 2004, we filed an initial license application with the U.S. Coast Guard and the Maritime Administration (MARAD) to allow us to receive and process LNG using Open Rack Vaporizer technology and to store and distribute natural gas at the facilities. In January 2007, MARAD issued a positive Record of Decision and approved our amended license application that incorporated the use of Closed Loop technology to the project. The issuance of the license is subject to various terms, criteria and conditions contained in the Record of Decision, including demonstration of financial responsibility, compliance with applicable laws and regulations, environmental monitoring and other customary conditions. As of December 31, 2006, we have incurred approximately $36.3 million of cash costs associated with our pursuit of the establishment of the MPEH™, which includes the advancement of the licensing process and the pursuit of commercial and financing arrangements for the project. We expect to spend approximately $12 million for licensing and commercialization of the project in 2007.

Currently we own 100 percent of the MPEH™ project. However, two entities have separate options to participate as passive equity investors for up to an aggregate 25 percent of our equity interest in the project (Notes 4 and 11). Future financing and commercial arrangements may also reduce our equity interest in the project.

MAIN PASS OIL FACILITIES

In December 2002, we and K1 USA Energy Production Corporation (K1 USA), a wholly owned subsidiary of k1 Ventures Limited (collectively K1), formed a joint venture, which acquired our Main Pass oil production facilities and related oil reserves. Until December 27, 2004 (see below), the joint venture was owned 66.7 percent by K1 USA and 33.3 percent by us. In connection with the formation of the joint venture, we received $13 million in proceeds, which were used to fully fund the reclamation costs for the Main Pass structures not essential to the planned future businesses at the site, and K1 USA received stock warrants to purchase 1.74 million shares of our common stock at a price of $5.25 per share, which expire in December 2007.

Until September 2003, the joint venture also had an option to acquire from us the Main Pass facilities that are planned for use in the MPEH™ project. In September 2003, we restructured the agreement and K1 USA now has the right to participate as a passive equity investor in up to 15 percent of our equity participation in the MPEH™ project. In connection with this agreement, K1 USA also received additional warrants to acquire up to 0.76 million shares of our common stock at $5.25 per share. These warrants expire in September 2008.

On December 27, 2004, we acquired K1 USA's 66.7 percent interest in the joint venture, bringing our ownership interest to 100 percent. In this transaction, we repaid the joint venture's debt totaling $8.0 million and released K1 USA from the future abandonment obligations related to the facilities.

The storm center of Hurricane Ivan passed within 20 miles east of Main Pass in September 2004. The Main Pass structures did not incur significant damage from Ivan but oil production was shut-in because of extensive damage to a third-party offshore terminal and connecting pipelines that provided throughput service for the sale of Main Pass sour crude oil. In May 2005 production resumed at Main Pass following successful modification of existing storage facilities to accommodate transportation of oil production from the field by barge. We incurred costs of approximately $8.2 million to modify these storage facilities. Insurance proceeds partially mitigated the financial impact of the storm. We received a total of $20.5 million for our insurance claims resulting from Hurricane Ivan, including $12.4 million of business interruption insurance proceeds, $0.6 million for other related expenditures and $7.5 million for costs related to the modification of the Main Pass facilities. These proceeds represent final settlement of our Hurricane Ivan insurance claims.

On August 29, 2005, the storm center of Hurricane Katrina passed within 50 miles west of Main Pass. While the Main Pass facilities and platforms did not suffer significant damage from Katrina, oil operations were temporarily shut-in to perform required repairs resulting from the storm. Oil production from Main Pass resumed in late November 2005. Subsurface inspections at Main Pass that commenced during the fourth quarter of 2005 indicated the primary oil structures did not sustain any significant structural damage from the storm, but identified one ancillary structure that required repairs. As of December 31, 2006 these repair costs totaled $2.8 million. We are pursuing reimbursement of these repair costs under terms of our insurance policies.

The crude oil produced at Main Pass contains significant amounts of sulphur, which is required to be removed during the refining process. There is a limited market for this sour crude oil, which sells at a discount to other crude oils. We currently have an exclusive short-term contract for sale of our Main Pass crude with one purchaser but continue to work towards establishing contracts with multiple purchasers covering the future sale of our Main Pass sour crude oil.

The Main Pass oil lease was subject to a 25 percent overriding royalty retained by its original third party owner after 36 million barrels of oil were produced, subject to a 50 percent net profits interest. In February 2005, we reached agreement with the original owner to eliminate the royalty interest in exchange for our assumption of a $3.9 million reclamation obligation at Main Pass. In addition, the original owner is entitled to a 6.25 percent overriding royalty in any new wells drilled on the lease.

See Notes 4 and 12 for additional information regarding our Main Pass oil facilities and related estimated proved oil reserves.

CAPITAL RESOURCES AND LIQUIDITY

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

	For Year Ended December 31,		
	2006	2005	2004
Continuing operations			
Operating	$ 99.3	$ 74.8	$ (29.7)
Investing	(231.1)	(143.1)	(75.8)
Financing	22.8	1.2	218.9

	For Year Ended December 31,		
	2006	2005	2004
Discontinued operations			
Operating	$ (4.9)	$ (4.7)	$ (5.5)
Investing	-	(0.1)	(5.9)
Financing	-	-	-
Total cash flow			
Operating	$ 94.4	$ 70.1	$ (35.1)
Investing	(231.1)	(143.2)	(81.7)
Financing	22.8	1.2	218.9

Comparison of Year-To-Year Cash Flows

Operating

Compared with the prior year, operating cash flow from our continuing operations in 2006 primarily reflects increased oil and gas revenues partially offset by increased working capital requirements and a $12.4 million net payment to settle litigation (see Item 3. "Legal Proceedings" elsewhere in this Form 10-K). Our operating cash flows during 2006 also reflect a $11.0 million net reimbursement of previously incurred exploration costs resulting from exploration agreements negotiated during 2006 (see "Operational Activities – Exploration Agreements" above). Our 2005 operating cash flows increased over comparable 2004 amounts primarily as a result of increased oil and gas revenues, working capital changes, including the advance billing and receipt of certain exploratory drilling costs from our drilling partners and the receipt of insurance proceeds related to our Main Pass business interruption claim (see "Main Pass Oil Facilities" above and Note 4), and a decrease in the amount of start-up costs incurred associated with the MPEH™. During each of the three years ending December 31, 2006, our operating cash flow also benefited from our Co-Chairmen receiving awards of immediately vested stock options in lieu of cash compensation (Note 8).

Cash used in our discontinued operations slightly increased during 2006 primarily reflecting $3.1 million of reclamation costs paid for work performed at our inactive Port Sulphur, Louisiana facilities as well as other increased caretaking costs related to the facility. We plan to perform significant reclamation activities as part of a modified reclamation plan for the Port Sulphur facilities in 2007 (see "Discontinued Operations – Sulphur Reclamation Obligations" below). Cash used in our discontinued operations declined during 2005 from 2004 as lower reclamation expenditures were partially offset by additional caretaking costs for our Port Sulphur facilities as a result of damages sustained from Hurricanes Katrina and Rita. Cash used in discontinued operations in 2004 included a final payment of $2.5 million for remaining reclamation work on the Main Pass structures not used for MPEH™ that is expected to be completed in 2007.

Investing

Our investing cash flow from continuing operations in 2006 reflects capital expenditures of $252.4 million, primarily for exploratory drilling costs as well as subsequent development of the related discoveries. For a discussion of our capital expenditures incurred during the three years ended December 31, 2006, see Items 1. and 2. "Business and Properties" located elsewhere in this Form10-K. We plan to drill 8-10 exploratory wells in 2007. We estimate that our capital expenditures will approximate $150 million during 2007, including approximately $40 million for costs incurred during 2006. Additional development capital expenditures will be driven by exploration successes. These planned capital expenditures may change as additional opportunities become available to us. We plan to fund our exploration and development activities with our available unrestricted cash, including proceeds from a term loan completed in January 2007 (see "Senior Term Loan Agreement" below), operating cash flows, and borrowings under our credit facility (see "Senior Secured Revolving Credit Facility" below). We plan to pursue additional debt or equity financing for our MPEH™ start-up activities. In addition, we will require commercial arrangements for the financing of the MPEH™ project.

Our investing cash flows also reflect the release to us of $16.5 million of previously escrowed U.S. government notes during 2006. During 2006, we used $3.9 million and $3.1 million of these escrowed funds to pay the semi-annual interest payments on our 6% convertible senior notes on January 2, 2006 and July 2, 2006, respectively and an aggregate $6.0 million to pay the $3.0 million semi-annual interest payments on our 5¼% convertible senior notes on April 6, 2006 and October 6, 2006. The

remaining $3.5 million of released funds represented interest payments we were no longer required to make on our convertible debt following completion of our debt conversion transactions (see "Debt Conversion Transactions" below) and which were used to fund a portion of the related amounts. Our remaining escrowed funds totaled $5.9 million at December 31, 2006 and are available to make semi-annual interest payments for the 5¼% convertible senior notes in 2007.

Our investing cash flow from continuing operations in 2005 primarily reflects capital expenditures of $161.3 million. In the fourth quarter of 2005, we received $3.5 million of insurance proceeds as partial reimbursement of the capital costs incurred to modify certain structures at Main Pass to allow for the transportation of oil from the field by barge (see "Main Pass Oil Facilities" above). Our investing cash flow also included the liquidation of $15.2 million of previously escrowed U.S. government notes to pay the semi-annual interest payments on our convertible senior notes (see "Securities Offerings" below), with $7.8 million of total interest paid for the 6% convertible notes being made in equal payments on January 2 and July 2, 2005 and $7.4 million of total interest paid for the 5¼% convertible notes being made in equal payments on April 6 and October 6, 2005.

Our investing cash flow from continuing operations in 2004 primarily reflects capital expenditures of $57.2 million. Our investing cash flow during 2004 also included the liquidation of $7.8 million of previously escrowed U.S. government notes to pay the first two semi-annual interest payments on our 6% convertible notes payable on January 2 and July 2, 2004. In connection with the issuance of $140 million of our 5¼% convertible notes we purchased $21.2 million of U.S. government securities to escrow the first six semi-annual interest payments payable on the notes. In 2004, we also received $2.5 million as final payment on the $13 million note receivable associated with a joint venture's acquisition of the oil facilities at Main Pass. As discussed in "Main Pass Oil Facilities" above, in December 2004 we acquired K1 USA's 66.7 percent interest in the joint venture by repaying the venture's $8.0 million of debt outstanding and assuming the reclamation obligation associated with the oil facilities at Main Pass.

During 2004, investing cash flow from discontinued operations reflected the $7.0 million payment to terminate a sulphur railcar lease, net of $1.1 million of proceeds received from sale of the related assets.

Financing

Cash provided by our continuing operations' financing activities during 2006 primarily reflects $28.8 million of net borrowings under our revolving credit facility (see "Senior Secured Revolving Credit Facility" below). We incurred costs of $0.5 million to establish the revolving credit facility. Our financing activities also included payments totaling $4.3 million in our debt conversion transactions (see "Debt Conversion Transactions" below). Financing activities also included the payment of $1.5 million of dividends on our convertible preferred stock (see "Convertible Preferred Stock" below and Note 6) and proceeds of $0.4 million from the exercise of stock options.

Cash provided by our continuing operations' financing activities during 2005 included proceeds from the exercise of stock options totaling $2.4 million partially offset by $1.1 million of dividends on our convertible preferred stock.

Cash provided by our continuing operations' financing activities during 2004 included $134.4 million of net proceeds from the issuance of our 5¼% convertible notes and the issuance of approximately 7.1 million shares of our common stock for net proceeds of $85.5 million (see "Securities Offerings" below and Note 5). Our financing activities also included the payment of $1.5 million of dividends on our convertible preferred stock.

Senior Secured Revolving Credit Facility

In April 2006, we established a new four-year, $100 million Senior Secured Revolving Credit Facility (the facility) for MOXY's oil and natural gas operations with a group of banks. The facility provides borrowing capacity based on estimates of MOXY's oil and natural gas reserves and had an initial borrowing base of $55 million. The borrowing base is re-determined on a semi-annual basis on April 1 and October 1 of each year based on MOXY's oil and natural gas reserves. In October 2006, the lenders increased the facility's borrowing base to $70 million. In January 2007, the borrowing base under this facility was reduced to $50 million following the closing of a new term loan (see "Senior Term Loan Agreement" below). The facility may be increased to $150 million with additional lender commitments. The credit agreement matures on April 19, 2010. Our borrowings under the facility totaled $28.8 million at

December 31, 2006. We repaid all borrowings under the credit facility following the closing of the term loan. We expect to use the facility for working capital and other general corporate purposes.

The variable-rate facility is secured by (1) substantially all the oil and gas properties (including related oil and natural gas proved reserves) of MOXY and (2) the pledge by McMoRan of its ownership interest in MOXY and by MOXY of its ownership interest in each of its wholly owned subsidiaries. The facility is guaranteed by McMoRan and each of MOXY's wholly owned subsidiaries and contains customary financial covenants and other restrictions.

Senior Term Loan Agreement

In January 2007, we entered into a Senior Term Loan Agreement (Term Loan) (Note 5). The loan agreement provides for a five-year, $100 million second lien senior secured term loan facility, which matures in January 2012. Proceeds at closing, net of related fees and discounts totaled approximately $98 million. We used the net proceeds to repay borrowings outstanding under the revolving credit facility ($46.4 million), and will use the remainder to finance our future oil and gas exploration and development activities, working capital requirements and for general corporate purposes.

The term loan contains customary financial covenants and other restrictions. An annual mandatory $10 million payment of principal is due each year commencing on December 31, 2008. The variable-rate loan is subject to certain prepayment premiums over the initial three years and is guaranteed by McMoRan and each of MOXY's wholly owned subsidiaries. Interest on the term loan will be paid on at least a quarterly basis. The term loan is secured with a second lien on our oil and gas properties, including Main Pass. In connection with the closing of the term loan, our revolving credit facility was amended to reduce its borrowing base from $70 million to $50 million.

Debt Conversion Transactions

In the first quarter of 2006, we privately negotiated transactions to induce conversion of $29.1 million of our 6% convertible senior notes and $25.0 million of our 5¼% convertible senior notes into approximately 3.6 million shares of our common stock based on the respective conversion prices for each set of convertible notes (see "Securities Offerings" below and Note 5). We paid an aggregate $4.3 million in the transactions and recorded an approximate $4.0 million net charge to expense. The net charge reflects the $4.3 million inducement payment, reflected in the accompanying consolidated statement of operations as other non-operating expense and included within the accompanying statements of cash flow as a financing activity, less $0.3 million of previously accrued interest expense recorded during 2005. We funded approximately $3.5 million of the cash payments from restricted cash held in escrow for funding interest payments on the convertible notes and paid the remaining portion with available unrestricted cash. As a result of these transactions, we expect to realize annual interest cost savings of approximately $3.1 million.

Securities Offerings

In October 2004, we completed two securities offerings with gross proceeds totaling $231 million. We issued approximately 7.1 million shares of our common stock at $12.75 per share for net proceeds of $85.5 million. We also completed a private placement of $140 million of 5¼% convertible senior notes due October 6, 2011 for net proceeds of $134.4 million. We used $21.2 million of the proceeds to purchase U.S. government securities that were placed in escrow to pay the first six semi-annual interest payments on the notes. The notes are otherwise unsecured. Interest payments are payable on April 6 and October 6 of each year. The first interest payment was paid on April 6, 2005. The notes are convertible at the option of the holder at any time prior to maturity into shares of our common stock at a conversion price of $16.575 per share. Beginning on October 6, 2009, we have the option of redeeming the notes for a price equal to 100 percent of the principal amount of the notes plus any accrued and unpaid interest on the notes prior to the redemption date provided the closing price of our common stock has exceeded 130 percent of the conversion price for at least 20 trading days in any consecutive 30-day trading period.

In July 2003, we issued $130 million of 6% convertible senior notes due July 2, 2008. Net proceeds totaled approximately $123.0 million, $22.9 million of which was used to purchase U.S. government securities that were placed in escrow and were used to pay the first six semi-annual interest payments. The notes are otherwise unsecured. Interest is payable on January 2 and July 2 of each year. The first interest payment was made on January 2, 2004. The notes are convertible, at the option of the

holder, at any time prior to maturity into shares of our common stock at a conversion price of $14.25 per share.

Convertible Preferred Stock

In June 2002, we completed a $35 million public offering of 1.4 million shares of our 5% mandatorily redeemable convertible preferred stock (Note 6). Each share has a stated value of $25 and is entitled to receive quarterly cash dividends at an annual rate of $1.25 per share. Each share is convertible at any time at the option of the holder into 5.1975 shares of our common stock, which is equivalent to $4.81 per share. We can redeem the preferred stock for cash after June 30, 2007, and must redeem it by June 30, 2012. At December 31, 2006, we had 1.2 million shares of convertible preferred stock outstanding. Dividends accrued on the convertible preferred stock totaled $1.5 million in 2006, 2005 and 2004.

Sales of Oil and Gas Properties

In February 2002, we sold three oil and gas properties for $60.0 million. The properties sold were Vermilion Block 196 (Lombardi), Main Pass Blocks 86/97 (Shiner), and 80 percent of our interests in Ship Shoal Block 296 (Raptor). During the first quarter of 2005, we reached agreement with the third-party purchaser to assign to us the 75 percent reversionary interest in Raptor effective February 1, 2005. Effective June 1, 2005, reversion of the interests in the other two properties occurred following payout. For more information regarding these and other oil and gas fields see Items 1. and 2. "Business and Properties" located elsewhere in this Form 10-K.

We farmed-out our interests in the West Cameron Block 616 field to a third party in June 2002. The third party drilled a total of four successful wells at the field. We retained a 5 percent overriding royalty interest, subject to adjustment, until aggregate production exceeded 12 Bcf of gas, net to the acquired interests. When aggregate production exceeded this threshold in September 2004, we exercised our option to convert to a 25 percent working interest and a 19.3 percent net revenue interest in three of the wells in the field and to a 10 percent overriding royalty interest in the fourth well.

Contractual Obligations and Commitments

In addition to our accounts payable and accrued liabilities ($118.3 million at December 31, 2006), we have other contractual obligations and commitments that will require payments in 2007 and beyond.

The table below summarizes the maturities of our 6% and 5¼% convertible notes (Note 5) and required redemption of our 5% convertible preferred stock (Note 6), our expected payments for retiree medical costs (Notes 8 and 11), our current exploration and development commitments and our remaining minimum annual lease payments as of December 31, 2006. The table also includes the incurrence of additional long term debt through our term loan arrangement that was completed in January 2007 (Note 5) (amounts in millions):

	Long Term Debt and Convertible Securities [a]	Retirement Benefits [b]	Oil & Gas Obligations [c]	Lease Payments [d]	Interest/ Dividend Payments [e]	Total
2007	$ -	$ 2.7	$ 47.7	$ 0.2	$ 25.7	$ 76.3
2008	110.9	2.1	0.4	0.2	25.7	139.3
2009	10.0	2.1	-	0.1	18.3	30.5
2010	10.0	2.1	-	-	17.1	29.2
2011	125.0	2.0	-	-	15.9	142.9
Thereafter	89.8	12.4	-	-	0.8	103.0
Total	$ 345.7	$ 23.4	$ 48.1	$ 0.5	$ 103.5	$ 521.2

a. Amounts due upon maturity subject to change based on future conversions by the holders of the securities. The outstanding balance payable to holders of record on the 5% convertible preferred stock totaled $29.8 million at December 31, 2006. We have the option of redeeming the outstanding convertible preferred stock after June 30, 2007 and must settle the balance by June 30, 2012 (Note 6). Amounts also include the annual mandatory $10 million principal payments on the term loan, commencing on December 31, 2008.

b. Includes anticipated payments under our employee retirement health care plan through 2016 (Note 8) and our future reimbursements associated with the contractual liability covering certain of our former

sulphur retiree's medical costs (Note 11). Amounts shown in 2007 are included within our accrued liabilities at December 31, 2006.

c. These oil & gas obligations primarily reflect our net working interest share of authorized exploration and development project costs at December 31, 2006 (see below for total estimated exploration and development expenditures for 2007). Amount also includes inventory purchase commitments relating to our drilling activities, primarily for tubulars and other related supplies. While these inventory purchases will be charged to other working interest owners as soon as permitted under applicable operating agreements, we likely will retain some level of inventory for some time before these can be charged to projects. This amount also includes $0.7 million third-party contractual consulting costs over the next two years (Note 11).
d. Amount primarily reflects leased office space in Houston, Texas, which terminates in April 2009.
e. Assumes no conversions of our outstanding 5% convertible preferred stock shares (resulting in $1.5 million dividend payments per year), no conversions of our convertible senior notes (the cash to satisfy the $6.0 million of interest payments due in 2007 for the 5¼% convertible notes is held in escrow at December 31, 2006) and a 12 percent effective annual interest rate on our term loan. The interest rate on the term loan is variable and a 0.1 percent change in the rate would change our cumulative interest on the term loan by approximately $0.4 million.

We expect to participate in the drilling of 8-10 exploratory wells during 2007. We expect to fund these activities with our available unrestricted cash, including the proceeds from our recently completed term loan transaction, operating cash flows and borrowings under our revolving credit facility. We expect our oil and gas capital expenditures for 2007 will total approximately $150 million, including approximately $40 million for capital costs incurred during 2006. Our capital expenditures are subject to change depending on the number of wells drilled, the result of our exploratory drilling, participant elections, availability of drilling rigs, the time it takes to drill each well, related personnel and material costs, and other factors, many of which are beyond our control. For more information regarding risk factors affecting our drilling operations see "Risk Factors" included in Item 1A. located elsewhere in this Form 10-K.

RESULTS OF OPERATIONS

Our only business segment is "Oil and Gas," which includes all oil and natural gas exploration and production operations of MOXY, including the oil production at Main Pass subsequent to December 27, 2004 (see "Main Pass Oil Facilities" above). We are pursuing a new business segment, "Energy Services," whose start-up activities are reflected as a single expense line item within the accompanying consolidated statements of operations. See "Discontinued Operations" below for information regarding our former sulphur segment.

We use the successful efforts accounting method for our oil and gas operations, which requires exploration costs, other than costs of successful drilling and in-progress exploratory wells, to be charged to expense as incurred (Note 1). We anticipate that we may experience operating losses during the near-term, primarily because of our significant planned exploration activities and the continued start-up costs associated with establishing the MPEH™ project.

Operations

Our operating loss during 2006 totaled $32.6 million, which reflects a $21.9 million loss associated with our oil and gas operations and $10.7 million of start-up costs to advance the licensing process and to pursue commercial arrangement for the MPEH™ project. Our oil and gas operations in 2006 reflect significantly higher revenues ($209.7 million) than in 2005 ($130.1 million) offset in part by increased corresponding production costs and depreciation, depletion and amortization charges. Our depletion, depreciation and amortization expense also included charges of $21.7 million and $12.2 million to reduce the respective carrying costs of the West Cameron Block 43 and Eugene Island Block 213 (Minuteman) fields to their estimated fair value at December 31, 2006. Our oil and gas results were further reduced by $67.7 million of exploration expenses, including $45.6 million for nonproductive well drilling and related costs.

Our operating loss during 2005 totaled $22.4 million, which included $0.2 million of income from our oil and gas operations, $9.7 million of start-up costs for the MPEH™ project and a $12.8 million charge for the settlement of litigation (see Item 3 "Legal Proceedings elsewhere in this Form 10-K). Our 2005 oil and gas operating results reflect significantly higher revenues ($130.1 million) than in 2004 ($29.8 million) partially offset by corresponding increases in production costs and depreciation, depletion

and amortization charges. Our oil and gas results were reduced by $63.8 million of exploration costs, including $49.6 million for nonproductive well drilling and related costs.

Our 2004 operating loss totaled $43.9 million, which included a $32.4 million loss from our oil and gas operations and $11.5 million of start-up costs for the MPEH™ project. The loss from our oil and gas operations included $36.9 million of exploration expenses and a $0.8 million impairment charge to reduce the net book value of the Eugene Island Block 97 field to its estimated fair value at December 31, 2004.

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

	2006	2005
Oil and natural gas revenues – prior year	$ 118,176	$ 15,611
Increase (decrease)		
Price realizations:		
Natural gas	(31,829)	25,031
Oil	8,953	4,861
Sales volumes:		
Natural gas	61,032	36,255
Oil	36,012	31,234
Plant products revenue	4,545	4,387
Overriding royalty and other	(172)	797
Oil and natural gas revenues - current year	$ 196,717	$ 118,176

See Item 6. "Selected Financial Data" elsewhere in this Form 10-K for operating data, including our sales volumes and average realizations for each of the three years in the period ended December 31, 2006.

2006 Compared with 2005

Our oil and natural gas revenues in 2006 increased substantially over amounts in 2005 reflecting significant increases in volumes sold of both natural gas and oil. During 2006 we sold oil and natural gas volumes totaling 23.9 billion cubic feet of natural gas equivalents (Bcfe) compared with 12.9 Bcfe in 2005. During 2006, we commenced production from 14 additional wells (see "Operational Activities – Production Update" above). Average realizations received for oil sold during 2006 increased by 12.5 percent over amounts received in 2005 reflecting higher oil prices during the first nine months of the year. Average realizations for natural gas sold during 2006 decreased 24 percent from amounts received during 2005. For a discussion of market factors affecting both natural gas and oil see "Overview – North American Natural Gas Environment" above. We expect our production volumes and associated revenue will increase during 2007.

Our 2006 revenues included $9.6 million of plant product sales associated with approximately 178,700 equivalent barrels of oil and condensate received for products (ethane, propane, butane, etc.) recovered from the processing of our natural gas, compared to $5.0 million for plant products from 106,700 equivalent barrels during 2005. Plant product revenues increased primarily from the commencement of production at the Hurricane and Long Point fields and the fourth quarter recompletion of the Deep Tern wells.

Our service revenues totaled $13.0 million in 2006 compared with $12.0 million in 2005. Our service revenue is primarily attributable to the management fee associated with the multi-year exploration venture (see "Operational Activities – Exploration Agreements above) and oil and gas processing fees for third party production at our Main Pass oil operations. During the second quarter of 2006, we substantially concluded our services agreement with a gas distribution utility. We received a total of $0.8 million associated with our services provided to the gas utility during 2006 compared to $1.8 million in the prior year. With the recent completion of the multi-year exploration venture, the end of our third-party processing arrangement at Main Pass and the cessation of our services agreement with the utility company, we expect our service revenues will substantially decrease in 2007 as compared to 2006.

Production and delivery costs totaled $53.1 million for 2006 compared with $29.6 million in 2005. This increase primarily reflects our increased production volumes during the year. Our production costs for 2006 also includes approximately $2.8 million of repair costs associated with hurricane-related

damage to a structure used in the oil operations at Main Pass. We are pursuing reimbursement of these repair costs under the terms of our insurance policies. The increase also reflects higher production costs associated with Gulf of Mexico oil and gas operations, including the cost of diesel, supply boats, chemicals and labor as compared with the 2005 periods. Well workover costs totaled $4.5 million for the year ended December 31, 2006 compared to $1.3 million in 2005. Our workover costs during 2006 primarily related to attempts to restore production from the Minuteman well at Eugene Island Block 213 (see below) in the first quarter of 2006 and from the Hurricane No. 1 well at South Marsh Island Block 217 in the second quarter of 2006.

Depletion, depreciation and amortization expense totaled $104.7 million for the year ended December 31, 2006 compared to $25.9 million last year. The increase primarily reflects higher production volumes resulting from new fields commencing production during 2006 (see "Operational Activities – Production Update"), as well as additional production from fields which commenced production during the second half of 2005. The increase also reflects fields with higher depreciable basis commencing production during 2006. As indicated in Note 1, we record depletion, depreciation and amortization expense on a field-by-field basis using the units-of-production method. Our depletion, depreciation and amortization rates are directly affected by estimates of proved reserve quantities, which are subject to a significant level of uncertainty, especially for fields with little or no production history. Subsequent revisions to individual fields' reserve estimates can yield significantly different depreciation, depletion and amortization rates.

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

The Minuteman well at Eugene Island Block 213 commenced production in February 2005. The well's production decreased significantly from initial rates until stabilizing at a gross rate approximating 3 MMcfe/d in the second quarter of 2005. The well was shut-in for both Hurricanes Katrina and Rita but returned to production following both storms at rates approximating 3 MMcfe/d. In late October 2005, the well was shut-in because of mechanical problems. In the first quarter of 2006, the operator performed workover activities on the well. The well resumed production in February 2006 but was subsequently shut-in because of mechanical issues. The well later resumed production at significantly reduced rates. Because of the significant uncertainty as to the timing and probability of success of potential remedial operations at this well, we reduced our investment in the Minuteman field to its estimated fair value at December 31, 2006 by recording a $12.2 million charge to depletion, depreciation and amortization expense.

At December 31, 2006, limited quantities of proved reserves were initially assigned to the West Cameron Block 43 field, pending production history to support additional reserves. As indicated in our fourth quarter 2006 financial results released on January 18, 2007, we were monitoring our investment in the West Cameron Block 43 field, which was in start-up operations and expected to be completed in the near term. In late January 2007, production commenced at the No. 3 well at lower than anticipated flow rates. The well's production decreased steadily and it shut-in late in February 2007. Our current assessment is that it is unlikely that proved reserves attributed to this field at December 31, 2006 will be recovered. Accordingly, we recorded a $21.7 million charge to depletion, depreciation and amortization expense in the accompanying consolidated statement of operations for the year ending December 31, 2006 to reduce the field's carrying cost to its currently estimated fair value. We continue to assess possible alternatives to restore production to the No. 3 well which, if performed with successful results, could be incorporated into potential plans for the West Cameron Block No. 4 well (see Items 1. and 2. "Business and Properties".)

The Cane Ridge well at Louisiana State Lease 18055, located onshore Vermilion Parish, commenced production in April 2006 at initial gross rates approximating 9 MMcfe/d. These initial rates decreased significantly after a few weeks of production and in early July the well was shut-in. The operator was unsuccessful in initial attempts to reestablish production from the well. In late December

2006, the operator assigned its ownership interest in the well to us and we are currently performing remedial operations in an attempt to restore production from the well. At December 31, 2006, our investment in the Cane Ridge well totaled $13.7 million. Because of the lack of sufficient historical production data for this well, we are unable to develop meaningful estimates of the ultimate recoverable reserves for this prospect.

The determination of oil and natural gas reserve estimates is a subjective process, and 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 that are difficult to predict and may vary considerably from actual results. In particular, reserve estimates 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 estimated reserves and related estimates of future cash flows. If the capitalized costs of an individual oil and gas property exceed the related estimated future net cash flows, reduction of the capitalized costs to the property's estimated fair value through a charge to our operating results is required (Note 1). For more information regarding the risks associated with our reserve estimation process see "Risk Factors" within Items 1A. elsewhere in this Form 10-K.

Our exploration expenses fluctuate based on the outcome of drilling exploratory wells, the structure of our drilling arrangements and the incurrence of geological and geophysical costs, including the cost of seismic data. Summarized exploration expenses are as follows (in millions):

	Years Ended December 31,	
	2006	2005
Geological and geophysical, including 3-D seismic purchases	$ 15.2 [a]	$ 7.4
Dry hole costs	45.6 [b]	49.6 [c]
Insurance and other	6.9	6.8
	$ 67.7	$ 63.8

a. Includes $8.1 million of compensation costs associated with outstanding stock-based awards following adoption of a new accounting standard (see "New Accounting Standards" below).
b. Includes nonproductive exploratory drilling and related costs for "Marlin" at Grand Isle Block 18 ($7.0 million), Vermilion Block 54 ($7.8 million), "Long Point Deep" at Louisiana State Lease 18091($14.9 million), "Denali" at South Pass Block 26 ($8.3 million) and the evaluation of the deeper objectives at "Zigler Canal" in Vermilion Parish, Louisiana ($1.7 million). Also includes the costs incurred during 2006 at "Cabin Creek" at West Cameron Block 95 ($2.7 million) and "Elizabeth" at South Marsh Island Block 230 ($2.5 million), which were evaluated as nonproductive in January 2006.
c. For listing of nonproductive exploratory well drilling and related costs for 2005 see "2005 Compared with 2004" below.

2005 Compared with 2004

Our oil and natural gas revenues in 2005 increased substantially over amounts in 2004 reflecting significant increases in volumes sold of both natural gas and oil. The increase in sales volumes reflects the establishment of production at four of our discoveries including from the Hurricane No. 1 well in March 2005, Deep Tern (C-1 sidetrack well in April 2005 and the C-2 well in late December 2004), the Minuteman well in February 2005 and the King Kong Nos. 1 and 2 wells in December 2005, together with the oil production associated with Main Pass, following acquisition of the remaining interest we did not own in late December 2004 (see "Main Pass Oil Facilities" above). Our 2005 sales volumes also reflect the reversion to us of interests in properties we sold in February 2002 (see "Capital Resources and Liquidity – Sale of Oil and Gas Properties" above). Our 2005 production also includes the increase in our net revenue interest in the West Cameron Block 616 field from 5 percent to approximately 19.3 percent following payout of the field in September 2004. Average realizations received during 2005 increased for both natural gas (52 percent) and oil (44 percent), excluding Main Pass, over realizations received in the prior year.

Our 2005 revenues included $5.0 million of plant product sales associated with approximately 106,700 equivalent barrels of oil and condensate compared to $0.5 million for plant products from 22,900

equivalent barrels during 2004. Plant product revenues increased primarily from the commencement of production at the Hurricane No. 1 and the Deep Tern wells. Our service revenues totaled $12.0 million in 2005 compared to $14.2 million in 2004.

Production and delivery costs totaled $29.6 million in 2005 compared to $6.6 million in 2004. The increase primarily reflects the production costs associated with the Main Pass oil operations, which totaled $19.2 million in 2005, and additional costs relating to increased natural gas and oil production for 2005 as compared with 2004. Production costs during 2005 also include hurricane damage repair costs of $4.2 million, including $3.9 million for Main Pass. 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.

Depletion, depreciation and amortization expense totaled $25.9 million in 2005 and $5.9 million in 2004. The increase primarily reflects production volumes from new fields with lower depreciable basis commencing production in the first half of 2005 and depletion, depreciation and amortization expense associated with oil production from Main Pass.

Summarized exploration expenses are as follows (in millions):

	Years Ended December 31,	
	2005	2004
Geological and geophysical, including 3-D seismic purchases	$ 7.4	$ 8.9
Dry hole costs	49.6 [a]	23.7 [b]
Insurance and other	6.8 [c]	4.3
	$ 63.8	$ 36.9

a. Includes nonproductive exploratory well drilling and related costs for "Elizabeth" at South Marsh Island Block 230 ($5.9 million) and "Cabin Creek" at West Cameron Block 95 ($10.8 million) during the fourth quarter of 2005. Nonproductive exploratory well costs during the interim 2005 periods included "Delmonico" at Louisiana State Lease 1706 ($9.8 million), "Korn" at South Timbalier Blocks 97/98 ($6.9 million), "Little Bay" at Louisiana State Lease 5097 ($12.1 million) and $1.3 million of well drilling costs for the "Caracara" well incurred after December 31, 2004 (see b below). We also charged approximately $1.4 million of expiring leasehold costs to exploration expense in 2005.

b. Reflects nonproductive exploratory well drilling and related costs for the deeper zones at the "Hurricane No. 1" well at South Marsh Island Block 217 ($0.5 million), "King of the Hill No. 1" at High Island Block 131 ($4.8 million), "Gandalf" at Mustang Island Block 829 ($2.0 million), "Poblano" at East Cameron Block 137 ($3.4 million), "Lombardi Deep" at Vermilion Block 208 ($7.2 million) and $0.9 million for the first-quarter 2004 costs incurred on the original Hurricane well at South Marsh Island Block 217. Also includes $3.8 million of drilling and related costs incurred through December 31, 2004 on the "Caracara" well at Vermilion Blocks 227/228, which was evaluated to be nonproductive in late January 2005. Our dry hole costs in 2004 also include a $1.0 million impairment charge to write off the remaining unproved leasehold costs associated with the Eugene Island Block 97 field.

c. Increase over the 2004 period includes higher delay rental payments to maintain portions of our lease acreage position.

Other Financial Results

Operating. Our general and administrative expenses totaled $20.7 million in 2006, $19.6 million in 2005 and $14.0 million in 2004. The 2006 amounts include the adoption of Statement of Accounting Standards No. 123 (revised 2004) "Share-Based Payment" (SFAS 123R) effective January 1, 2006 (see "New Accounting Standards" below). We charged approximately $7.1 million of related stock-based compensation costs to general and administrative expense during 2006 compared with $0.6 million in 2005. General and administrative expenses during 2006 benefited from a reduction in legal costs following settlement of litigation in the fourth quarter of 2005. The increase in 2005 from 2004 reflects higher personnel costs associated with our expanded exploration and production activities and additional costs associated with the litigation discussed below. Additionally, during 2005, we incurred $1.0 million of costs associated with contributions, employee assistance and other

administrative costs following Hurricane Katrina, of which $0.8 million was charged to general and administrative expense and the remainder to exploration expense. Noncash compensation costs charged to general and administrative expense for stock-based awards totaled $0.6 million in 2005 and $0.4 million in 2004 (Note 8).

In late 2005, we reached an agreement in principle with plaintiffs to settle previously disclosed class action litigation in the Delaware Court of Chancery relating to the 1998 merger of Freeport-McMoRan Sulphur Inc. and McMoRan Oil & Gas Co. In accordance with the terms of the settlement, we paid $17.5 million in cash into a settlement fund in the first quarter of 2006, the plaintiffs provided a complete release of all claims, and the Delaware litigation was dismissed with prejudice. In the fourth quarter of 2005, we recorded a $12.8 million charge to expense, net of the amount of anticipated insurance proceeds. During 2006, we received $5.1 million of insurance proceeds related to our settlement costs, and we recorded the $0.4 million of insurance proceeds in excess of our original estimate as a reduction of our operating costs for 2006. These amounts are separately disclosed in the accompanying consolidated statements of operations.

Our operating results in 2006 included insurance recoveries totaling $3.3 million, including the receipt of the initial insurance settlement related to our Hurricane Katrina property loss claim and the final settlement related to our Hurricane Ivan claim affecting Main Pass. We expect additional future recoveries related to claims arising from Hurricane Katrina, although amounts have not yet been fully determined or recorded. Our 2005 operating results reflect receipt of business interruption insurance proceeds related to our Main Pass claims following Hurricane Ivan in September 2004. The final amount of proceeds received under the Hurricane Ivan insurance claims was $20.5 million, of which $12.4 million related to business interruption, $0.6 million related to other damages and the remainder to reimburse property damage including the modification of the storage and loading facilities. See "Main Pass Oil Facilities" above for more information regarding hurricane-related insurance claims at Main Pass.

Non-Operating. Interest expense, net of capitalized interest, totaled $10.2 million in 2006, $15.3 million in 2005 and $10.3 million in 2004. We capitalized interest totaling $5.3 million in 2006, $2.1 million in 2005 and $0.9 million during 2004. Interest expense has increased over the past three years following the issuance of our convertible notes and borrowings under our revolving credit facility during the second half of 2006 (see "Capital Resources and Liquidity" above). Capitalized interest has increased during the same timeframe reflecting the increases in our interest expense and our oil and gas drilling and development activities.

Other non-operating income (expense) totaled ($1.9) million in 2006, $6.2 million in 2005 and $2.2 million in 2004. Other expense in 2006 reflects reduced interest income on our lower cash equivalent balances and $4.3 million of charges to expense resulting from the conversion transactions of our convertible senior notes during the first quarter of 2006 (see "Capital Resources and Liquidity – Debt Conversion Transactions" above). Our non-operating income for 2005 and 2004 primarily reflects higher interest income on our cash equivalent balance, which reflects the completion of our two capital transactions in October 2004. Interest income for the three years ended December 31, 2006 totaled $2.2 million in 2006, $6.1 million in 2005 and $2.0 million in 2004.

DISCONTINUED OPERATIONS

We sold substantially all of our remaining sulphur assets in June 2002. We ceased our sulphur-mining activities in August 2000. Accordingly, the results of operations of our former sulphur business are recorded as discontinued operations in the accompanying consolidated financial statements. Our discontinued operations' results are summarized in Note 7.

Our discontinued operations resulted in income of $0.4 million in 2004 and losses of $2.9 million in 2006 and $8.2 million in 2005. The results during 2006 primarily reflect additional caretaking costs associated with the ongoing work at our Port Sulphur, Louisiana facilities resulting from damages incurred from Hurricane Katrina. At December 31, 2006, we recorded a $3.4 million charge to discontinued operations expense to increase the accrued reclamation costs for these facilities to their estimated fair value under related accounting requirements (Note 11). The aggregate estimated closure costs for Port Sulphur approximates $12.1 million. We are currently planning to accelerate closure of the Port Sulphur facilities and are considering several different alternatives under our reclamation plans. We estimate that we may incur up to $10.4 million of these costs during 2007 under our currently anticipated closure plan,

which is subject to change pending regulatory approval of the final plans. We expect insurance recovery associated with claims from 2005 hurricanes will partially mitigate these costs. In the fourth quarter we were notified by our insurers that our initial Port Sulphur property damage claims totaling $3.5 million had been approved. We received these proceeds in the first quarter of 2007. We recorded the $3.5 million as discontinued operations' income in the accompanying consolidated statements of income at December 31, 2006. On February 28, 2007, we received from our insurers the final $4.2 million proof of loss on our Port Sulphur property damage claims, which are expected to be collected by mid-year 2007. These amounts will be recorded as discontinued operations income in our first quarter 2007 results. At December 31, 2006 we also recorded a $3.2 million reduction in the contractual liability to reimburse a third party for a portion of the postretirement benefit costs relating to certain retired former sulphur employees (Note 11). The decrease primarily resulted from a significant decline in the number of participants covered by the related benefit plans.

Our loss from discontinued operations in 2005 primarily reflected costs associated with required repairs to facilities at Port Sulphur resulting from damages sustained during Hurricanes Katrina and Rita, as well as a $6.5 million charge to increase our previously estimated reclamation costs for the remaining facilities at Port Sulphur. Our net loss in 2005 was partially offset by a $3.5 million reduction in the contractual liability (discussed above). The decrease in the contractual liability primarily reflects the expected future benefit associated with the initiation of the federal prescription drug program.

The net income from our discontinued operations in 2004 primarily resulted from a $5.2 million reduction in the contractual liability (discussed above). The decrease in the contractual liability reflects a reduction in the number of participants covered by the plans and certain plan amendments made by the plan sponsor. The other costs associated with our discontinued operations include caretaking and insurance costs associated with our closed sulphur facilities and legal costs.

Sale of Sulphur Assets

In June 2002, we sold substantially all the assets used in our sulphur transportation and terminaling business for $58.0 million in gross proceeds. At December 31, 2006 and 2005, approximately $0.4 million and $1.0 million, respectively, of funds from these transactions (including accumulated interest income) 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 potential funding for certain retained environmental obligations discussed further below.

In the sales transaction, we also agreed to be responsible for certain historical environmental obligations relating to our sulphur transportation and terminaling assets and have also agreed to indemnify certain parties from potential 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 Inc. (now a subsidiary of Mosaic Company), one of the purchasers of our sulphur assets, from certain potential obligations, including environmental obligations, other than liabilities existing and identified as of the closing of the sale, associated with the historical oil and gas operations undertaken by the Freeport-McMoRan companies prior to the 1997 merger of Freeport-McMoRan Inc. and IMC Global. As of December 31, 2006, we have paid approximately $0.2 million to settle certain claims related to these assumed liabilities. Although potential liabilities for these assumed environmental obligation may exist, no specific liability has been identified that we believe is reasonably probable of requiring us to fund any future amount. See Item 1A. "Risk Factors" located elsewhere in this Form 10-K.

MMS Bonding Requirement Status

We are currently meeting our financial obligations relating to the future abandonment of our Main Pass facilities with the Minerals Management Service (MMS) using financial assurances from MOXY. We and our subsidiaries' ongoing compliance with applicable MMS requirements are subject to meeting certain financial and other criteria.

Sulphur Reclamation Obligations

In the first quarter of 2002, we entered into turnkey contracts with Offshore Specialty Fabricators Inc. (OSFI) for the reclamation of the Caminada and Main Pass sulphur mines and related facilities located offshore in the Gulf of Mexico. OSFI completed its reclamation activities at the Caminada mine site in 2002. OSFI commenced the removal of the structures not essential to any future business opportunities at Main Pass in the second half of 2002.

We agreed to pay OSFI $13 million for the removal of these structures and OSFI substantially completed the related reclamation work. In July 2004, we settled litigation arising from a dispute between us and OSFI. In accordance with the settlement, we paid OSFI the remaining $2.5 million amount due for the reclamation and OSFI will complete the remaining reclamation work, currently planned for 2007. This reclamation obligation is included in current liabilities in the accompanying consolidated balance sheets at December 31, 2006 and 2005. OSFI currently has no obligation regarding the reclamation of Main Pass structures comprising the MPEH™ project. Pursuant to the settlement, OSFI has an option to participate in the MPEH™ project for up to 10 percent of our equity interest on a basis parallel to our agreement with K1 USA (see Notes 3 and 4).

As of December 31, 2006, we have recognized a liability of $7.4 million relating to the future reclamation of the MPEH™ related facilities at Main Pass. The ultimate timing of reclamation for these structures is dependent on the success of our efforts to use these facilities at the MPEH™ project as described above.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Management's Discussion and Analysis of our financial condition and results of operation is based upon our consolidated financial statements, which have been prepared in conformity with U.S. generally accepted accounting principles. 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 assumptions 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. Beginning in 2006 we also have reclamation obligations related to wells and facilities located onshore Louisiana, which are subject to the laws and regulations of the State of Louisiana. Effective January 1, 2003, we implemented a new accounting standard that significantly modified the method we use to recognize and record our accrued reclamation obligations (see below).

Our sulphur reclamation obligations are associated with our former sulphur mining operations. In June 2000 we elected to cease all sulphur mining operations, which resulted in a charge to fully accrue the estimated reclamation costs associated with our Main Pass sulphur mine and related facilities and the related storage facilities at Port Sulphur, Louisiana. We had previously fully accrued all estimated costs associated with the closed Caminada and Grand Ecaille mines and related sulphur facilities. During 2002, we entered into fixed cost contracts to perform a substantial portion of our sulphur reclamation work. All the work associated with the Caminada mine and related facilities was subsequently completed and the reclamation work on structures not essential to any future business opportunities at Main Pass has also been substantially completed (see "Discontinued Operations – Sulphur Reclamation Obligations").

Effective January 1, 2003, we adopted Statement of Financial Accounting Standard No. 143, "*Accounting for Asset Retirement Obligations*" (SFAS 143). SFAS 143 requires that we record the fair value of our estimated asset retirement obligations in the period incurred, rather than accrued as the related reserves are produced. Upon implementation of SFAS 143, we recorded the fair value of the

obligations relating to our oil and gas operations together with the related additional asset cost. For our closed sulphur facilities, we did not record any related assets with respect to our asset retirement obligations but reduced our accrued obligations by approximately $19.4 million to their estimated fair value. We recorded an aggregate $22.2 million gain upon the adoption of this standard, which was reflected as "cumulative effect gain on change in accounting principle."

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

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

We revise our reclamation and well abandonment estimates whenever events indicated its is warranted but, at a minimum are revised at least once every year. Revisions have been made for (1) changes in the projected timing of certain reclamation costs because of changes in the estimated timing of the depletion of the related proved reserves for our oil and gas properties and new estimates for the timing of the reclamation for the structures comprising the MPEH™ project and Port Sulphur facilities, and (2) changes in our credit-adjusted, risk-free interest rate. Over the period these reclamation costs would be incurred, the credit-adjusted, risk-free interest rates ranged from 9.33 percent to 10 percent at December 31, 2006 and 8.35 percent to 10.0 percent at December 31, 2005.

The following table summarizes the estimates of our reclamation obligations at December 31, 2006 and 2005 (in thousands):

	Oil and Gas		Sulphur	
	2006	2005	2006	2005
Undiscounted cost estimates	$ 41,600	$ 39,210	$ 42,244	$ 41,802
Discounted cost estimates	$ 25,175	$ 21,760	$ 23,094	$ 21,786

The following table summarizes the approximate effect of a 1 percent change in both the estimated inflation and market risk premium rates (in millions):

	Inflation Rate		Market Risk Premium	
	+1%	-1%	+1%	-1%
Oil & Gas reclamation obligations:				
Undiscounted	$ 3.5	$ (3.2)	$ 0.4	$ (0.4)
Discounted	1.5	(1.6)	0.2	(0.2)
Sulphur reclamation obligations:				
Undiscounted	5.3	(4.4)	0.3	(0.3)
Discounted	1.5	(1.8)	0.1	(0.1)

- **Depletion, Depreciation and Amortization.** As discussed in Note 1, depletion, depreciation and amortization for our oil and gas producing assets is calculated on a field-by-field basis using the units-of-production method based on current estimates of our proved and proved developed 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 have fully depreciated all of our other remaining depreciable assets.

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

1) The determination of our proved oil and natural gas 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 natural gas prices and future operating costs.
b) Projected production levels and the timing and amounts of future development, remedial, 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 estimated proved reserves for each property were 10 percent higher at December 31, 2006, we estimate that our annual depletion, depreciation and amortization expense for 2006 would have decreased by approximately $2.8 million, while a 10 percent decrease in estimated proved reserves for each property would have resulted in an approximate $3.7 million increase in our depletion, depreciation and amortization expense for 2006. 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 a third party for a portion of their postretirement medical benefit costs relating to certain retired former sulphur employees. This obligation is based on numerous estimates of future health care cost trends, retired sulphur employees' life expectancy, liability discount rates and other factors. We also have similar obligations for our employees, although the number of employees covered by our plan is significantly less than those covered under our contractual obligation to the third party. 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.

To evaluate the present value of the contractual liability at December 31, 2006, an initial health care cost trend of 9 percent was used in 2007, with annual ratable decreases until reaching 5 percent in 2012. A one percentage point increase in the initial health care cost trend rate would have increased our recorded liability by $1.0 million at December 31, 2006; while a one percentage point decrease would have reduced our recorded liability by $0.9 million. We used a 7.5 percent discount at December 31, 2006 and a 7 percent discount rate at December 31, 2005. A one-percentage point increase in the

discount rate would have decreased our net loss by approximately $0.5 million in 2006, while a one-percentage point decrease in the discount rate would have increased our net loss by approximately $0.6 million. See Notes 8 and 11 for additional information regarding postretirement and other employee benefit costs, including a $3.2 million and $3.5 million reduction in the contractual liability at December 31, 2006 and 2005, respectively, resulting from a decrease in the number of participants covered by the related benefit plans during 2006 and the future benefit expected from the initiation of a federal drug subsidy program at year-end 2005. In the case of our obligation relating to certain retired former sulphur employees the impact of any changes in assumptions are charged to results of operations in the period in which they occur.

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 the level of natural gas sales volumes during 2006, a change of $0.10 per Mcf in the average realized price would have an approximate $1.5 million net impact on our revenues and net loss. A $1 per barrel change in average oil realization based on the level of oil sales during 2006 would have an approximate $1.4 million net impact on our revenues and net loss. Based on the $7.05 per Mcf annual realization for our 2006 sales of natural gas, a 10 percent fluctuation in our 2006 sales volumes would have had an approximate $10.3 million impact on our revenues and $6.1 million net impact on our net loss. Based on the $60.55 per barrel annual realization for our 2006 sales of oil, a 10 percent fluctuation in our sales volumes would have had an approximate $8.4 million impact on revenues and an approximate $5.5 million net impact on our net loss.

Our production during 2007 is subject to certain uncertainties, many of which are beyond our control, including the timing and flow rates associated with the initial production from our discoveries, weather-related factors and shut-in or recompletion activities on any of our oil and gas properties or on third-party owned pipelines or facilities. Any of these factors, among others, could materially affect our estimated annualized sales volumes. For more information regarding risks associated with oil and gas production see Item 1A. "Risk Factors" elsewhere in this Form 10-K.

Our convertible senior notes have fixed interest rates of 6% and 5¼%. Borrowings under our revolving credit facility and term loan (see "Capital Resources and Liquidity – Senior Secured Revolving Credit Facility" and Note 5) expose us to interest rate risks. At the present time we do not hedge our exposure to fluctuations in interest rates.

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.

NEW ACCOUNTING STANDARDS

Inventory Costs

In November 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 151, "Inventory Costs, an amendment of ARB No. 43, Chapter 4." SFAS No. 151 clarifies that abnormal amounts of idle facility expense, freight handling costs and wasted materials (spoilage) should be recognized as current-period charges and requires the allocation of fixed production overheads to inventory based on the normal capacity of the production facilities. As required, we adopted SFAS No. 151 on January 1, 2006; and upon adoption, there was no material impact on our accounting for inventory costs.

Stock-Based Payments

Effective January 1, 2006, we adopted the fair value recognition provisions of Statement of Financial Accounting Standards No. 123 (revised 2004), "Share-Based Payment" or (SFAS No. 123R), using the modified prospective transition method. Under this transition method, compensation cost recognized in 2006 includes: (a) compensation costs for all stock option awards granted to employees prior to, but not yet vested as of January 1, 2006, based on the grant-date fair value estimated in accordance with the original provisions of SFAS No. 123, and (b) compensation cost for all stock option awards granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS No.123R. Fair value of stock option awards granted to employees was calculated using the Black-Scholes-Merton option valuation model before and after adoption of SFAS No. 123R. Other stock-based awards charged to expense under SFAS No. 123

continue to be charged to expense under SFAS No. 123R (Note 1). These include stock options granted to non-employees and advisory directors as well as restricted stock units. Results for prior periods have not been restated.

As a result of adopting SFAS No. 123R, our net income applicable to common stock for the year ended December 31, 2006, was $14.6 million lower than if we had continued to record share-based compensation charges under APB Opinion No. 25. McMoRan expects to record approximately $15 million of compensation expense during 2007 related to its unvested stock-based awards.

Compensation cost charged against earnings for stock-based awards is shown below (in thousands).

	2006	2005	2004
General and administrative expenses	$ 7,120	$ 615	$ 405
Exploration expenses	8,104	1,052	702
Main Pass Energy Hub start-up costs	598	10	-
Total stock-based compensation cost	$ 15,822	$ 1,677	$ 1,107

As of December 31, 2006, total compensation cost related to nonvested stock option awards not yet recognized in earnings was approximately $14.1 million, which is expected to be recognized over a weighted average period of approximately 1.1 years.

Accounting for Uncertainty in Income Taxes.
In June 2006, the Financial Accounting Standards Board (FASB) issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes," (FIN 48). FIN 48 clarifies the accounting for income taxes by prescribing the minimum recognition threshold a tax position is required to meet before being recognized in the financial statements. FIN 48 also provides guidance on derecognition, measurement, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN 48 is effective for the first fiscal year beginning after December 15, 2006. We do not expect implementation of FIN 48 will have any material effect on our results of operations or statement of financial position.

Fair Value Measurements.
In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements." SFAS No. 157 establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), clarifies the definition of fair value within that framework, and expands disclosures about the use of fair value measurements. In many of its pronouncements, the FASB has previously concluded that fair value information is relevant to the users of financial statements and has required (or permitted) fair value as a measurement objective. However, prior to the issuance of this statement, there was limited guidance for applying the fair value measurement objective in GAAP. This statement does not require any new fair value measurements in GAAP. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007, with early adoption allowed. We are still reviewing the provisions of SFAS No. 157 and have not determined the impact of adoption.

Accounting for Defined Benefit Pension and Other Postretirement Plans.
In September 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132R." SFAS No. 158 represents the completion of the first phase of FASB's postretirement benefits accounting project and requires an entity to:

- Recognize in its statements of financial position an asset for a defined benefit postretirement plan's overfunded status or a liability for a plan's underfunded status,
- Measure a defined benefit postretirement plan's assets and obligations that determine its funded status as of the end of the employer's fiscal year, and
- Recognize changes in the funded status of a defined benefit postretirement plan in comprehensive income/loss in the year in which the changes occur.

SFAS No. 158 does not change the manner of determining the amount of net periodic benefit cost included in net income (loss) or address the various measurement issues associated with postretirement benefit plan accounting. The requirement to recognize the funded status of a defined benefit

postretirement plan is effective for year-end 2006. The adoption of SFAS No. 158 increased both our long-term and current liabilities and increased our stockholders' deficit (see Notes 1 and 8).

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. For more information regarding our current reclamation and environmental obligations see "Critical Accounting Policies and Estimates" and "Discontinued Operations" above.

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. The cost and amount of such insurance for the oil and gas industry is subject to overall insurance market conditions, which were adversely affected in a significant fashion by the 2005 hurricane activity.

CAUTIONARY STATEMENT

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

Item 8. Financial Statements and Supplementary Data

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is defined in Rule 13a-15(f) or 15d-15(f) under the Securities Exchange Act of 1934 as a process designed by, or under the supervision of, the Company's principal executive and principal financial officers and effected by the Company's Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that:

- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the Company's assets;
- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and
- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements.

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

Our management, including our principal executive officer and principal financial officer, assessed the effectiveness of our internal control over financial reporting as of the end of the fiscal year covered by this annual report on Form 10-K. In making this assessment, our management used the criteria set forth in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our management's assessment, management concluded that, as of the end of the fiscal year covered by this annual report on Form 10-K, our Company's internal control over financial reporting is effective based on the COSO criteria.

Ernst & Young LLP, an independent registered public accounting firm, has issued their audit report on our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2006 as stated in their report dated March 12, 2007, which is included herein.

Glenn A. Kleinert
President and Chief
Executive Officer

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that McMoRan Exploration Co. maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). McMoRan's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, management's assessment that McMoRan Exploration Co. maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, McMoRan Exploration Co. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the COSO criteria.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of McMoRan Exploration Co. as of December 31, 2006 and 2005, and the related consolidated statements of operations, cash flow, and changes in stockholders' deficit for each of the three years in the period ended December 31, 2006 of McMoRan Exploration Co., and our report dated March 12, 2007 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana,
March 12, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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, 2006 and 2005, and the related consolidated statements of operations, cash flow and changes in stockholders' deficit for each of the three years in the period ended December 31, 2006. 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 the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of McMoRan Exploration Co. at December 31, 2006 and 2005, and the consolidated results of its operations and its cash flow for each of the three years in the period ended December 31, 2006 in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, in 2006, the Company changed its method of accounting for stock-based compensation, and as of December 31, 2006, the Company changed its method of accounting for pension and postretirement benefits.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of McMoRan Exploration Co.'s internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 12, 2007 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana
March 12, 2007

McMoRan EXPLORATION CO.
CONSOLIDATED BALANCE SHEETS

	December 31, 2006	December 31, 2005
	(In Thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents:		
Continuing operations, $0.3 million restricted at December 31, 2005	$ 17,830	$ 131,179
Discontinued operations, all restricted	441	1,005
Restricted investments (Note 1)	5,930	15,155
Accounts receivable (Note 1)	45,636	36,954
Inventories (Note 1)	25,034	7,980
Prepaid expenses	16,190	1,348
Current assets from discontinued operations, excluding cash	6,051	2,550
Total current assets	117,112	196,171
Property, plant and equipment, net (Note 4)	282,538	192,397
Discontinued sulphur business assets	362	375
Restricted investments and cash (Note 1)	3,288	10,475
Other assets	5,377	8,218
Total assets	$ 408,677	$ 407,636
LIABILITIES AND STOCKHOLDERS' DEFICIT		
Current liabilities:		
Accounts payable	$ 85,504	$ 64,023
Accrued liabilities	32,844	49,192
Accrued interest and dividends payable	5,479	5,635
Current portion of accrued sulphur reclamation costs (Note 7)	12,909	4,724
Current portion of accrued reclamation costs for oil and gas facilities	2,604	-
Other current liabilities from discontinued operations	3,678	5,462
Total current liabilities	143,018	129,036
Long-term debt (Note 5)	244,620	270,000
Accrued oil and gas reclamation costs	23,272	21,760
Accrued sulphur reclamation costs	10,185	17,062
Contractual postretirement obligation related to discontinued operations (Note 11)	9,831	11,517
Other long-term liabilities (Note 4)	17,151	15,890
Commitments and contingencies (Note 11)		
Mandatorily redeemable convertible preferred stock, net of unamortized offering costs of $0.8 million and $0.9 million at December 31, 2006 and 2005, respectively	29,043	28,961
Stockholders' 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, 30,740,275 shares and 27,122,538 shares issued and outstanding, respectively	307	271
Capital in excess of par value of common stock	477,178	410,139
Unamortized value of restricted stock units	-	(110)
Accumulated deficit	(499,725)	(452,071)
Accumulated comprehensive loss	(1,273)	-
Common stock held in treasury, 2,433,545 shares and 2,428,121 shares, at cost, respectively	(44,930)	(44,819)
Stockholders' deficit	(68,443)	(86,590)
Total liabilities, convertible preferred stock and stockholders' deficit	$ 408,677	$ 407,636

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

McMoRan EXPLORATION CO.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2006	2005	2004
	(In Thousands, Except Per Share Amounts)		
Revenues:			
Oil and natural gas	$ 196,717	$ 118,176	$ 15,611
Service	13,021	11,951	14,238
Total revenues	209,738	130,127	29,849
Costs and expenses:			
Production and delivery costs	53,134	29,569	6,559
Depletion, depreciation and amortization expense	104,724	25,896	5,904
Exploration expenses	67,737	63,805	36,903
General and administrative expenses	20,727	19,551	14,036
Start-up costs for Main Pass Energy Hub™ Project	10,714	9,749	11,461
Exploration expense reimbursement	(10,979)	-	-
Litigation settlement, net of insurance proceeds	(446)	12,830	-
Insurance recovery	(3,306)	(8,900)	(1,074)
Total costs and expenses	242,305	152,500	73,789
Operating loss	(32,567)	(22,373)	(43,940)
Interest expense, net	(10,203)	(15,282)	(10,252)
Other (expense) income, net	(1,946)	6,185	2,160
Loss from continuing operations	(44,716)	(31,470)	(52,032)
(Loss) income from discontinued operations	(2,938)	(8,242)	361
Net loss	(47,654)	(39,712)	(51,671)
Preferred dividends and amortization of convertible preferred stock issuance costs	(1,615)	(1,620)	(1,642)
Net loss applicable to common stock	$ (49,269)	$ (41,332)	$ (53,313)
Basic and diluted net loss per share of common stock:			
Net loss from continuing operations	(1.66)	$(1.35)	$(2.85)
Net loss from discontinued operations	(0.10)	(0.33)	0.02
Net loss per share of common stock	$(1.76)	$(1.68)	$(2.83)
Average common shares outstanding:			
Basic and diluted	27,930	24,583	18,828

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

McMoRan EXPLORATION CO.
CONSOLIDATED STATEMENTS OF CASH FLOW

	Years Ended December 31,		
	2006	2005	2004
	(In Thousands)		
Cash flow from operating activities:			
Net loss	$ (47,654)	$ (39,712)	$ (51,671)
Adjustments to reconcile net loss to net cash used in operating activities:			
Loss (income) from discontinued operations	2,938	8,242	(361)
Depletion, depreciation and amortization	104,724	25,896	5,904
Exploration drilling and related expenditures	45,591	49,621	23,679
Stock warrants granted – Main Pass Energy Hub™	-	-	188
Compensation associated with stock-based awards	15,822	1,677	1,107
Loss on induced conversion of convertible senior notes	4,301	-	-
Amortization of deferred financing costs	1,891	2,225	1,599
Reclamation and mine shutdown expenditures	(670)	(4)	(288)
Other	997	(261)	285
(Increase) decrease in working capital:			
Accounts receivable	(4,523)	(2,182)	(6,990)
Accounts payable and accrued liabilities	7,743	36,469	(3,231)
Inventories	(17,050)	(7,127)	103
Prepaid expenses	(14,845)	(48)	
(Increase) decrease in working capital	(28,675)	27,112	(10,118)
Net cash provided by (used in) continuing operations	99,265	74,796	(29,676)
Net cash used in discontinued operations	(4,916)	(4,681)	(5,459)
Net cash provided by (used in) operating activities	94,349	70,115	(35,135)
Cash flow from investing activities:			
Exploration, development and other capital expenditures	(252,369)	(161,262)	(57,241)
Property insurance reimbursement	3,947	3,500	-
Purchase of restricted investments	-	-	(21,191)
Proceeds from restricted investments	16,505	15,150	7,800
Acquisition of K-Mc I LLC, net of acquired cash of $0.6 million	-	-	(7,415)
Increase in restricted investments	(229)	(502)	(265)
Proceeds from disposition of oil and gas properties	1,021	-	2,550
Proceeds from sale of other property plant and equipment	50	-	-
Net cash used in continuing activities	(231,075)	(143,114)	(75,762)
Net cash used in discontinued operations	-	(66)	(5,920)
Net cash used in investing activities	(231,075)	(143,180)	(81,682)
Cash flow from financing activities:			
Net borrowings under senior secured revolving credit facility	28,750	-	-
Payments for induced conversion of convertible senior notes	(4,301)	-	-
Proceeds from issuance of 5¼% convertible senior notes	-	-	140,000
Net proceeds from equity offering	-	-	85,478
Financing costs	(531)	-	(5,624)
Dividends paid on convertible preferred stock	(1,494)	(1,129)	(1,531)
Proceeds from exercise of stock options and other	389	2,363	610
Net cash provided by continuing operations	22,813	1,234	218,933
Net cash activity from discontinued operations	-	-	-
Net cash provided by financing activities	22,813	1,234	218,933

McMoRan EXPLORATION CO.
CONSOLIDATED STATEMENTS OF CASH FLOW
(Continued)

	Years Ended December 31,		
	2006	2005	2004
		(In Thousands)	
Net (decrease) increase in cash and cash equivalents	(113,913)	(71,831)	102,116
Cash and cash equivalents at beginning of year	132,184	204,015	101,899
Cash and cash equivalents at end of year	18,271	132,184	204,015
Less restricted cash from continuing operations	-	(278)	(3,726)
Less restricted cash from discontinued operations	(441)	(1,005)	(980)
Unrestricted cash and cash equivalents at end of year	$ 17,830	$ 130,901	$ 199,309
Interest paid	$ 9,382	$ 15,150	$ 7,800
Income taxes paid	$ -	$ -	$ -

The accompanying notes, which include information *regarding* noncash transactions, are an integral part of these consolidated financial statements.

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

	Years Ended December 31,		
	2006	2005	2004
Preferred stock:			
Balance at beginning and end of year	$ -	$ -	$ -
Common stock:			
Balance at beginning of year representing 27,122,538 shares in 2006, 26,670,574 shares in 2005 and 19,181,251 shares in 2004	271	267	192
Shares issued in debt conversion transactions representing 3,552,494 shares (Note 5)	36	-	-
Shares issued on equity offering representing 7,130,000 shares (at $12.75 per share) (Note 5)	-	-	71
Exercise of stock options representing 26,823 shares in 2006, 255,699 shares in 2005 and 82,220 shares in 2004	-	3	1
Restricted stock units vested and other representing 30,104 shares in 2006, 46,709 in 2005 and 42,258 shares in 2004	-	-	1
Mandatorily redeemable preferred stock conversions representing 8,316 shares in 2006, 149,556 shares in 2005 and 234,845 shares in 2004	-	1	2
Balance at end of year representing, 30,740,275 shares in 2006, 27,122,538 shares in 2005 and 26,670,574 shares in 2004	307	271	267
Capital in Excess of Par Value:			
Balance at beginning of year	410,139	406,458	319,530
Shares issued in debt conversion transactions (Note 5)	52,513	-	-
Mandatorily redeemable preferred stock conversions	40	719	1,130
Stock-based compensation expense (Note 1)	15,822	1,168	561
Exercise of stock options	389	2,363	610
Exercise of stock options through tender of outstanding shares	-	1,051	464
Dividends on preferred stock and amortization of issuance cost	(1,615)	(1,620)	(1,642)
Reclass unamortized value of restricted stock units on adoption of new accounting standard	(110)	-	-
Shares issued in equity offering	-	-	85,407
Restricted stock unit grants	-	-	210
Issuance of stock warrants	-	-	188
Balance at end of year	477,178	410,139	406,458
Unamortized value of restricted stock units:			
Balance beginning of year	(110)	(619)	(955)
Reclass unamortized value of restricted stock units on adoption of new accounting standard	110		
Deferred compensation associated with restricted stock units (Note 1)	-	-	(210)
Amortization of related deferred compensation	-	509	546
Balance end of year	-	(110)	(619)
Accumulated Deficit:			
Balance at beginning of year	(452,071)	(412,359)	(360,688)
Net loss	(47,654)	(39,712)	(51,671)
Balance at end of year	(499,725)	(452,071)	(412,359)

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

	Years Ended December 31,		
	2006	2005	2004
Accumulated Comprehensive Loss:			
Balance at beginning of year	-	-	-
Adoption of new accounting standard (Notes 1 and 8)	(1,273)	-	-
Balance at end of year	(1,273)	-	-
Common Stock Held in Treasury:			
Balance at beginning of year representing, 2,428,121 shares in 2006, 2,345,759 in 2005 and 2,302,068 shares in 2004	(44,819)	(43,293)	(42,672)
Tender of 5,424 shares in 2006, 82,362 shares in 2005 and 43,691 shares in 2004 associated with the exercise of stock options and the vesting of restricted stock	(111)	(1,526)	(621)
Balance at end of year representing 2,433,545 shares in 2006, 2,428,121 shares in 2005 and 2,345,759 shares in 2004	(44,930)	(44,819)	(43,293)
Total stockholders' deficit	$ (68,443)	$ (86,590)	$ (49,546)

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation. The consolidated financial statements of McMoRan Exploration Co. (McMoRan), a Delaware Corporation, include the accounts of those subsidiaries where McMoRan directly or indirectly has more than 50 percent of the voting rights and for which the right to participate in significant management decisions is not shared with other shareholders. McMoRan consolidates its wholly owned McMoRan Oil & Gas LLC (MOXY) and Freeport-McMoRan Energy LLC (Freeport Energy) subsidiaries. On December 27, 2004, Freeport Energy acquired the remaining ownership interest in a joint venture, K-Mc Venture I LLC (K-Mc I), it did not already own and began consolidating the joint venture's financial results. McMoRan accounted for its investment in the joint venture using the equity method for the periods between December 16, 2002 and December 27, 2004 (Note 4). The ownership interest in the joint venture was transferred from Freeport Energy to MOXY in April 2006.

McMoRan's investments in unincorporated legal entities represented by undivided interests in other oil and gas joint ventures and partnerships engaged in oil and gas exploration, development and production activities are pro rata consolidated, whereby a proportional share of each joint venture's and partnership's assets, liabilities, revenues and expenses are included in the accompanying consolidated financial statements in accordance with McMoRan's working and net revenue interests in each joint venture and partnership.

All significant intercompany transactions have been eliminated. Certain prior year amounts have been reclassified to conform to the current year presentation. Changes in the accounting principles applied during the years presented are discussed below under the caption "Accounting for Stock-Based Compensation" and "Other New Accounting Standards."

As a result of McMoRan's exit from the sulphur business, 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.

Nature of Operations. McMoRan is an oil and gas exploration and production company engaged directly through its subsidiaries, joint ventures or partnerships with other entities in the exploration, development, production and marketing of crude oil and natural gas. McMoRan's operations are located entirely in the United States, specifically offshore in the Gulf of Mexico and onshore in the Gulf Coast region (Louisiana and Texas). McMoRan is also seeking to establish a liquefied natural gas (LNG) terminal at Main Pass Block 299 (Main Pass) in the Gulf of Mexico that would be capable of receiving and processing LNG and storing and distributing natural gas.

McMoRan's production of oil and natural gas involves lifting oil and natural gas to the surface and gathering, treating and processing hydrocarbons to extract liquids from natural gas. McMoRan's production costs include all costs incurred to operate or maintain its wells and related equipment and facilities. Examples of these costs include:

- labor costs to operate the wells and related equipment and facilities;
- repair and maintenance costs, including costs associated with re-establishing production from a geological structure that has previously produced;
- material, supplies, and fuel consumed and services utilized in operating the wells and related equipment and facilities, including marketing and transportation costs; and
- property taxes and insurance applicable to proved properties and wells and related equipment and facilities.

McMoRan's oil and natural gas revenues include a component for reimbursements of marketing and transportation costs, which are recorded as a corresponding reduction of production and delivery costs.

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

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

Accounts Receivable. The components of accounts receivable follow:

	December 31,	
	2006	2005
	(In Thousands)	
Accounts receivable:		
Customers	$ 19,151	$ 19,156
Joint interest partners	24,883	17,360
Other	1,602	438
Total accounts receivable	$ 45,636	$ 36,954

Inventories. Product inventories totaled $1.1 million at December 31, 2006 and $1.0 million at December 31, 2005, consisting entirely of oil at Main Pass. Materials and supplies inventory totaled $23.9 million at December 31, 2006 and $7.0 million at December 31, 2005 and represents the cost of supplies to be used in McMoRan's drilling activities, primarily drilling pipe and tubulars. These costs will be partially reimbursed by third party participants in wells supplied with these materials. McMoRan's inventories are stated at the lower of average cost or market. There have been no required reductions in the carrying value of McMoRan's inventories for any of the periods presented.

Property, Plant and Equipment.
Oil and Gas. McMoRan follows the successful efforts method of accounting for its oil and natural gas exploration and development activities. Costs associated with drilling and development activities are included as a reduction of investing cash flow in the accompanying consolidated statements of cash flow.

- Geological and geophysical costs and costs of retaining unproved properties and undeveloped 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.
  * The costs of exploratory wells that have found oil and natural gas reserves that cannot be classified as proved when drilling is completed continue to be capitalized as long as the well has found a sufficient quantity of reserves to justify its completion as a producing well and sufficient progress is being made in assessing the proved reserves and the economic and operating viability of the project. Management evaluates progress on such wells on a quarterly basis.
  * If proved reserves are not discovered the related drilling costs are charged to exploration expense.

- Acquisition costs of leases and development activities are capitalized.

- Other exploration costs are charged to expense as incurred.

- Depletion, depreciation and amortization expense is determined on a field-by-field basis using the units-of-production method, with depletion rates for leasehold acquisition costs based on estimated proved reserves and depletion, depreciation and amortization rates for well and related facility costs based on proved developed reserves associated with each field. The depletion, depreciation and amortization rates are changed whenever there is an indication of the need for a revision but, at a minimum, are revised once every year. Any such revisions are accounted for prospectively as a change in accounting estimate.

- Gains or losses from dispositions of McMoRan's interests in oil and gas properties are included in earnings under the following conditions:

    * All or part of an interest owned is sold to an unrelated third party; if only part of an interest is sold, there is no substantial uncertainty about the recoverability of cost applicable to the interest retained; and
    * McMoRan has no substantial obligation for future performance (e.g, drilling a well(s) or operating the property without proportional reimbursement of costs relating to the interest sold).

- Interest expense allocable to significant unproved 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 $5.3 million in 2006, $2.1 million in 2005 and $0.9 million in 2004.

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. See Note 7 for more discussion regarding McMoRan's sulphur-related charges now included in the accompanying consolidated statements of operations within the caption "(Loss) income from discontinued operations."

Asset Impairment. Costs of unproved oil and gas properties are assessed periodically and a loss is recognized if the properties are deemed impaired. 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 and development costs based on operating budget forecasts.

The determination of oil and natural gas reserve estimates is a subjective process, and 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 that are difficult to predict and may vary considerably from actual results. In particular, reserve estimates 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 estimated reserves and related future cash flow estimates. If the capitalized cost of an individual oil and gas property exceeds the related estimated future net cash flows, an impairment charge to reduce the capitalized costs to the property's estimated fair value is required.

The Minuteman well at Eugene Island Block 213 commenced production in February 2005. The well's production decreased significantly from initial rates until stabilizing at a gross rate approximating 3 MMcfe/d in the second quarter of 2005. The well was shut in for both Hurricanes Katrina and Rita but returned to production following both storms at rates approximating 3 MMcfe/d. In late October 2005, the well was shut in because of mechanical problems. In the first quarter of 2006, the operator performed workover activities on the well. The well resumed production in February 2006 but was subsequently shut-in because of mechanical problems. The well has resumed production but at significantly reduced rates. Because of uncertainties as to the timing and probability of success of potential remedial

operations at this well, McMoRan reduced its investment in the Minuteman field to its estimated fair value at December 31, 2006, resulting in a $12.2 million charge to depletion, depreciation and amortization expense.

At December 31, 2006, limited quantities of proved reserves were assigned to the West Cameron Block 43 field, pending production history to support additional reserves. McMoRan indicated in its fourth quarter 2006 results, released on January 18, 2007, that it was monitoring its investment in the West Cameron Block 43 field which was in start-up operations and expected to be completed in the near-term. In late January 2007, production commenced at the No. 3 well at lower than anticipated flow rates. The well's production decreased steadily and it shut-in late in February 2007. McMoRan's current assessment is that it is unlikely that proved reserves attributed to this field at December 31, 2006 will be recovered. Accordingly, McMoRan recorded a $21.7 million charge to depletion, depreciation and amortization expense in the accompanying consolidated statement of operations for the year ending December 31, 2006 to reduce the field's carrying costs to its currently estimated fair value.

The Cane Ridge well at Louisiana State Lease 18055, located onshore in Vermilion Parish, commenced production in April 2006 at initial rates approximating 9 MMcfe/d. These initial rates decreased significantly and in early July 2006 the well was shut-in. The operator was unsuccessful in initial attempts to reestablish production from the well. In late December 2006, the operator assigned its ownership interests in the well to McMoRan and its private partner. McMoRan is currently performing remedial operations in an attempt to restore production from the well. At December 31, 2006, McMoRan's investment in the Cane Ridge well totaled $13.7 million.

At December 31, 2004, as a result of a reduction in the estimated proved reserves for its Eugene Island Block 97 field, McMoRan recorded a $0.8 million impairment charge to depletion, depreciation and amortization expense. McMoRan also charged the remaining $1.0 million of unproved leasehold costs associated with the field to exploration expense.

Restricted investments and cash. Restricted investments and cash (excluding discontinued operations) totaled $9.2 million at December 31, 2006 and $25.9 million at December 31, 2005. These amounts include $5.9 million and $15.4 million classified as current at December 31, 2006 and 2005, respectively. The current amount for 2005 includes $0.3 million of proceeds held in escrow for McMoRan's share of a portion of the drilling and development costs associated with the West Cameron Block 43 prospect. These escrowed amounts are classified as cash and cash equivalents in the accompanying consolidated balance sheets. McMoRan's restricted investments include U.S. government securities, plus accrued interest thereon, pledged as security for semi-annual interest payments made through July 2, 2006, for McMoRan's outstanding 6% convertible senior notes and payments made or scheduled through October 6, 2007 for McMoRan's 5¼% convertible senior notes (Note 5). Restricted cash classified as long-term includes $3.2 million of escrowed funds at December 31, 2006 and 2005 for certain assumed environmental liabilities (Note 11). McMoRan has $0.4 million of restricted cash associated with its discontinued sulphur operations (Note 7).

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

McMoRan has a number of producing fields that have been awarded royalty relief under the "Deep Gas Royalty Relief" program instituted by the Minerals Management Service (MMS). Under this program, the leases in which McMoRan has obtained relief are eligible for suspensions of the obligation to pay federal royalties on up to 25 Bcf of production, with each field's eligible amount of relief determined by specific MMS criteria and subject to their final approval. During the years ended December 31, 2006 and 2005, McMoRan recognized $1.9 million and $4.7 million, respectively, of additional oil and natural gas revenues associated with its awarded royalty relief. The royalty relief granted under this program is subject to certain annually adjusted price thresholds established by the MMS. If actual realized prices exceed the threshold on an annualized basis (as calculated using average daily NYMEX closing prices) then royalties suspended under this program would have to be repaid to the MMS with interest. The price threshold was not exceeded for the years ending December 31, 2006 and 2005. McMoRan recognizes oil

and gas revenues from production on properties eligible for royalty relief as the amounts are earned and whether or not the current MMS price threshold in effect has been exceeded. If the price threshold is exceeded, McMoRan defers all such revenues until the threshold price is no longer exceeded.

Service Revenue. McMoRan records the gross amount of reimbursements for costs from third parties as service revenues whenever McMoRan is the primary obligor with respect to the source of such costs, and it has discretion in the selection of how the related service costs are incurred and when it has assumed the credit risk associated with the reimbursement for such service costs. The service costs associated with these third-party reimbursements are also recorded within the applicable cost and expenses line item in the accompanying consolidated financial statements.

McMoRan's service revenues have been generated primarily through its management fee related to the multi-year exploration venture (Note 2), the fees associated with management services provided to k1 Ventures Limited in connection with its ownership of a gas distribution utility, fees for processing third-party oil production through the oil facilities at Main Pass and standardized industry (COPAS) overhead charges McMoRan receives as operator of oil and gas properties.

Major Customers. Sales of McMoRan's oil and natural gas production to major customers totaled 95 percent to five purchasers in 2006, 83 percent to four purchasers in 2005 and 65 percent to two purchasers in 2004. All of McMoRan's customers are located in the United States.

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

McMoRan used estimates prepared by third parties in determining its 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. See Note 11 for information regarding McMoRan's reclamation estimates at December 31, 2006 and 2005.

Accumulated Comprehensive Loss. McMoRan follows Statement of Financial Accounting Standards (SFAS) 130 "Reporting Comprehensive Income" for the reporting and display of comprehensive income (loss) (net loss minus other comprehensive income, or all other changes in net assets from nonowner sources) and its components. McMoRan did not have any comprehensive income (loss) items until it adopted SFAS 158 "Accounting for Defined Benefit and Other Postretirement Plans" on December 31, 2006 (see Other New Accounting Standards below and Note 8). McMoRan's comprehensive loss for 2006 follows (in thousands):

Net loss	$ (47,654)
Adjustment to apply SFAS No. 158	(1,273)
Total comprehensive loss	$ (48,927)

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

McMoRan's use of financial contracts to manage risks has been limited. McMoRan had no financial contracts during the three years ended December 31, 2006. McMoRan currently has no forward oil or gas sales contracts or other derivative contracts.

Share Purchase Program. McMoRan's Board of Directors has authorized an open market share purchase program for up to 2.5 million shares of its common stock. McMoRan did not purchase any shares of its common stock during the three-year period ending December 31, 2006. As of December 31, 2006, McMoRan had purchased 2,244,635 shares of its common stock at an average cost of $18.56 per share under its open market share purchase program.

Restricted Stock Units. Under McMoRan's stock-based compensation plans (Note 8), the Board of Directors granted 50,000 restricted stock units (RSUs) in April 2002, 100,000 RSUs in May 2003 and 12,500 RSUs in February 2004. The RSUs are converted ratably into an equivalent number of shares of McMoRan common stock on the grant anniversary dates over the following three years, unless deferred. There were no RSUs granted in 2006 or 2005. RSUs converted into common stock totaled 29,165 shares in 2006 and 45,833 shares in 2005. Upon issuance of the RSUs, unearned compensation equivalent to the market value at the date of grants, totaling approximately $0.2 million for the grant in April 2002, $1.3 million for the grant in May 2003 and $0.2 million for the grant in February 2004, was recorded as deferred compensation in stockholders' deficit and is charged to expense over the three-year vesting period of each respective grant. McMoRan charged approximately $0.1 million of this deferred compensation to expense in 2006 and $0.5 million in both 2005 and 2004. Deferred compensation associated with remaining unvested RSUs at December 31, 2006 is immaterial.

Earnings Per Share. Basic net loss per share of common stock was calculated by dividing the loss applicable to continuing operations, the income (loss) from discontinued operations, and the net 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, the net loss applicable to continuing operations includes preferred stock dividends and related charges.

McMoRan had a net loss from continuing operations for each of the three years in the period ending on December 31, 2006. Accordingly, McMoRan's diluted per share calculation for these periods was equivalent to its basic net loss per share calculation because it excluded the assumed exercise of stock options and stock warrants whose exercise prices were less than the average market price of McMoRan's common stock during these periods, as well as the assumed conversion of McMoRan's 5% mandatorily redeemable convertible preferred stock, 6% convertible senior notes and 5¼% convertible senior notes. These instruments were excluded for these periods because they were considered to be anti-dilutive, meaning their inclusion would have decreased the reported net loss per share for these periods. The excluded common share amounts are summarized below (in thousands):

	Years Ended December 31,		
	2006	2005	2004
In-the-money stock options [a,b]	1,097	1,336	2,243
Shares issuable upon exercise of stock warrants [a,c]	1,753	1,800	1,654
Shares issuable upon assumed conversion of 5% mandatorily redeemable preferred stock [d]	6,205	6,214	6,363
Shares issuable upon assumed conversion of 6% convertible senior notes [e]	7,079	9,123	9,123
Shares issuable upon assumed conversion of 5¼% convertible senior notes [f]	6,938	8,446	8,446

a. McMoRan uses the treasury stock method to determine the amount of in-the-money stock options and stock warrants to include in its diluted earnings per share calculation.
b. Represents stock options with an exercise price less than the average market price for McMoRan's common stock for the periods presented.
c. Includes stock warrants issued to K1 USA Energy Production Corporation in December 2002 (1.74 million shares) and September 2003 (0.76 million shares). The warrants are exercisable for McMoRan common stock at any time over their respective five-year terms at an exercise price of $5.25 per share (Note 4).

d. Amount represents total equivalent common stock shares assuming conversion of 5% mandatorily redeemable preferred stock (Note 5). Preferred dividends and related costs totaled $1.6 million in 2006 and 2005, and $1.7 million in 2004.
e. Amount represents total equivalent common stock shares assuming conversion of 6% convertible senior notes (Note 5). Net interest expense on the 6% convertible senior notes totaled $4.7 million in 2006, $8.1 million during 2005 and $8.5 million in 2004.
f. Amount represents total equivalent common stock shares assuming conversion of 5¼% convertible senior notes (Note 5). The amount would have been reduced in 2004 if included in the diluted earning per share calculation to reflect the 87-day period the notes were outstanding (October 6 – December 31, 2004). The amount that would have otherwise been included in the diluted earning per share calculation in 2004 was 2,013,000 equivalent common stock shares. Net interest expense on the 5¼% convertible senior notes totaled $4.2 million in 2006, $7.2 million in 2005 and $1.8 million in 2004.

Accounting for Stock-Based Compensation. Prior to January 1, 2006, McMoRan accounted for options granted under its stock-based employee compensation plans (see "Stock-Based Compensation Plans" below) under the recognition and measurement criteria of Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations, as permitted by Statement of Financial Accounting Standards (SFAS) No. 123, "Accounting for Stock-Based Compensation." APB Opinion No. 25 required compensation cost for stock options to be recognized based on the difference on the date of grant, if any, between the quoted market price of the stock and the amount an employee must pay to acquire the stock (i.e., the intrinsic value). Because McMoRan's stock-based compensation plans require that the option exercise price be at least the market price on the date of grant, McMoRan generally recognized no compensation cost on the grant or exercise of its employees' options. However, in certain instances there was a difference between the date McMoRan awarded stock options and the date of ultimate approval of the stock option grant, which resulted in compensation charges (see Note 8). McMoRan has also awarded restricted stock units under the plans, which resulted in compensation costs being recognized in earnings based on the intrinsic value on the date of grant.

Effective January 1, 2006, McMoRan adopted the fair value recognition provisions of SFAS No. 123 (revised 2004), "Share-Based Payment" (SFAS No. 123R), using the modified prospective transition method. Under this method, compensation cost recognized in 2006 includes (a) compensation costs for all stock option awards granted to employees prior to, but not yet vested as of, January 1, 2006, based on the grant-date fair value estimated in accordance with the original provisions of SFAS No. 123, and (b) compensation cost for all stock option awards granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123R. In addition, other stock-based awards charged to expense under SFAS No.123 continue to be charged to expense under SFAS No. 123R. These include stock options granted to non-employees and advisory directors as well as restricted stock units. Results for prior periods have not been restated. McMoRan recognizes compensation costs for awards that vest over several years on a straight-line basis over the vesting period. McMoRan's stock-based awards provide for an additional year of vesting after an employee retires. For awards to retirement-eligible employees, McMoRan records one year of amortization of the awards' estimated fair value on the date of grant. In addition, prior to adoption of SFAS No. 123R McMoRan recognized forfeitures as they occurred in its SFAS No. 123 pro forma disclosures. Beginning January 1, 2006, McMoRan includes estimated forfeitures in its compensation cost and updates the estimated forfeiture rate through the final vesting date of the awards.

As a result of adopting SFAS No. 123R, McMoRan's net loss applicable to common stock for the year ended December 31, 2006, was $14.6 million higher than if it had continued to record share-based compensation charges under APB Opinion No. 25. McMoRan's basic and diluted net loss per share amounts were $0.52 per share higher for the year ended December 31, 2006 as a result of the adoption of SFAS 123R.

McMoRan currently has no income tax benefits for deductions resulting from the exercise of stock options because of its significant net operating loss carryforwards, all of which have been reserved with a full valuation allowance (Note 9).

Stock-Based Compensation Cost. Compensation cost charged against earnings for stock-based awards is shown below (in thousands).

	Year Ended December 31,		
	2006	2005	2004
Cost of options awarded to employees (including Directors)	$ 15,129[a]	$ 858[b]	$ 281[b]
Cost of options awarded to non-employees and Advisory Directors	588	310	280
Cost of restricted stock units	105	509	546
Total stock-based compensation cost	$ 15,822	$ 1,677	$ 1,107

a. Includes $5.8 million of compensation charges associated with immediately vested stock options granted to McMoRan's Co-Chairmen in lieu of receiving any cash compensation during 2006. Also includes $1.9 million of compensation charges related to stock options granted to retirement-eligible employees, which resulted in one-year's compensation expense being immediately recognized at the date of the stock option grant (see "Accounting for Stock-Based Compensation" above).

b. Reflects compensation charge resulting from difference between the market price on the award date and the market price on the ultimate date of grant (Note 8). The amortization of the remaining $1.0 million of compensation costs resulting from these types of stock option grants ceased upon adoption of SFAS No. 123R.

As of December 31, 2006, McMoRan has eight stock-based employee and director compensation plans, which are described in Note 8. The fair value of each option award is estimated on the date of grant using a Black-Scholes-Merton option valuation model. Expected volatility is based on implied volatilities from the historical volatility of McMoRan's stock and to a lesser extent on traded options on McMoRan stock. McMoRan uses historical data to estimate option exercise, forfeitures and expected life of the options. When appropriate, employees who have similar historical exercise behavior are grouped for valuation purposes. The risk-free interest rate is based on Federal Reserve rates in effect for bonds with maturity dates equal to the expected term of the option at the date of grant. McMoRan has not paid, and has no current plan to pay, cash dividends on its common stock. The assumptions used to value stock option awards during the year ended December 31, 2006 are noted in the following table:

	2006
Fair value (per share) of stock option on grant date	$ 11.85[a]
Expected and weighted average volatility	55.5%
Expected life of options (in years)	7[a]
Risk-free interest rate	4.5%

a. Not included in these amounts are immediately vested stock options (500,000 shares granted to the Co-Chairmen in lieu of any cash compensation for 2006), having an expected life of six years and a grant date fair value of $11.52 per share.

The total intrinsic value of options exercised during the year ended December 31, 2006 was less than $0.1 million. As of December 31, 2006, McMoRan had approximately $14.1 million of total unrecognized compensation costs related to unvested stock options, which is expected to be recognized over a weighted average period of approximately 1.1 years.

The following table illustrates the effect on McMoRan's net loss and net loss per share for the years ended December 31, 2005 and 2004, had it applied the fair value recognition provisions of SFAS No. 123 to stock-based awards granted under its stock-based compensation plans (in thousands, except per share amounts):

	2005	2004
Basic net loss applicable to common stock, as reported	$ (41,332)	$ (53,313)
Add: Stock-based employee compensation expense recorded in net income for restricted stock units and employee stock options	1,367	827
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards	(11,439)	(8,347)
Pro forma diluted net loss applicable to common stock	$ (51,404)	$ (60,833)
Net loss per share:		
Basic and diluted – as reported	$ (1.68)	$ (2.83)
Basic and diluted – pro forma	$ (2.09)	$ (3.23)

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

	Years Ended December 31,	
	2005	2004
Fair value (per share) of stock options	$ 11.45	$ 11.00
Risk free interest rate	4.5%	3.9%
Expected volatility rate	61%	65%
Expected life of options (in years)	7	7
Assumed annual dividend	-	-

Other New Accounting Standards. In November 2004, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 151, "Inventory Costs, an amendment of Accounting Research Bulletin No. 43, Chapter 4." (SFAS No. 151). SFAS No. 151 clarifies that abnormal amounts of idle facility expense, freight handling costs and wasted materials (spoilage) should be recognized as current-period charges and requires the allocation of fixed production overheads to inventory based on the normal capacity of the production facilities. McMoRan adopted SFAS No. 151 on January 1, 2006 and its adoption had no material affect on its results of operations.

Accounting for Uncertainty in Income Taxes. In June 2006, the FASB issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes," (FIN 48). FIN 48 clarifies the accounting for income taxes by prescribing the minimum recognition threshold a tax position is required to meet before being recognized in the financial statements. FIN 48 also provides guidance on derecognition, measurement, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN 48 is effective for the first fiscal year beginning after December 15, 2006. McMoRan does not expect implementation of FIN 48 will have any material effect on its results of operations or statement of financial position.

Fair Value Measurements.
In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements." SFAS No. 157 establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), clarifies the definition of fair value within that framework, and expands disclosures about the use of fair value measurements. In many of its pronouncements, the FASB has previously concluded that fair value information is relevant to the users of financial statements and has required (or permitted) fair value as a measurement objective. However, prior to the issuance of this statement, there was limited guidance for applying the fair value measurement objective in GAAP. This statement does not require any new fair value measurements in GAAP. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007, with early adoption allowed. McMoRan is still reviewing the provisions of SFAS No. 157 and has not determined the impact of adoption.

Accounting for Defined Benefit Pension and Other Postretirement Plans.
In September 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132R." SFAS No. 158 represents the completion of the first phase of FASB's postretirement benefits accounting project and requires an entity to:

- Recognize in its statements of financial position an asset for a defined benefit postretirement plan's overfunded status or a liability for a plan's underfunded status,
- Measure a defined benefit postretirement plan's assets and obligations that determine its funded status as of the end of the employer's fiscal year, and
- Recognize changes in the funded status of a defined benefit postretirement plan in comprehensive income/loss in the year in which the changes occur.

SFAS No. 158 does not change the manner of determining the amount of net periodic benefit cost included in net income (loss) or address the various measurement issues associated with postretirement

benefit plan accounting. The requirement to recognize the funded status of a defined benefit postretirement plan is effective for year-end 2006. The impact of adopting SFAS 158 on individual line items in McMoRan's December 31, 2006 balance sheet is as follows (in thousands):

	Before Applying SFAS No. 158	Adjustment	After Applying SFAS No. 158
Accrued liabilities	$ 32,219	$ 625	$ 32,844
Other long-term liabilities	16,503	648	17,151
Accumulated other comprehensive loss	-	(1,273)	(1,273)

2. OIL & GAS EXPLORATION ACTIVITIES

McMoRan's oil and gas operations are conducted through MOXY, whose operations and properties are located almost exclusively offshore on the Continental Shelf of the Gulf of Mexico and onshore in the Gulf Coast region. Additional information regarding McMoRan's oil and gas operations is included below.

Acreage

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

The Chevron exploration agreement expired on January 1, 2004, at which time McMoRan's right to continue to identify prospects and drill to earn leasehold interests not previously earned expired, except for those properties as to which McMoRan had committed to drill an exploration well or otherwise received an extension from Chevron. On December 31, 2006, McMoRan retained rights or interests in seven leases covering approximately 32,000 gross acres and 20,000 net acres related to this agreement.

In January 2006, McMoRan negotiated a farm-out transaction with a major oil company in which it obtained exploration rights to over 100,000 gross acres in southern Louisiana and on the Gulf of Mexico shelf. This five-year agreement allows McMoRan to earn acreage by drilling a specified minimum number of wells. Under this arrangement, the original lease owner may elect to participate in certain wells after casing point and may elect to participate in other wells as a joint interest owner.

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

A summary of McMoRan's approximate acreage position is included below (unaudited).

	Number of Leases	Gross Acres	Net Acres
At December 31, 2006	400	370,000	132,000

Exploration Funding Arrangements

McMoRan intends to maintain its aggressive exploration drilling activities during 2007. McMoRan is funding its activities with available unrestricted cash, including proceeds from its term loan transaction completed in January 2007 (Note 5), its operating cash flow, and borrowings under its revolving credit facility.

Exploration Agreement with Plains Exploration & Production Company

In the fourth quarter of 2006, McMoRan entered into an exploration agreement with Plains Exploration & Production Co. (Plains) whereby Plains will participate in up to nine of McMoRan's exploration prospects for approximately 55 percent to 60 percent of McMoRan's initial ownership interests in the prospects. Subsequent elections may increase Plains' participation in certain of these prospects. Under the agreement Plains paid McMoRan $20 million for these leasehold interests and related prospect costs. McMoRan reflected $19.0 million of this payment as operating income in the accompanying consolidated statements of operations within the caption titled "Reimbursement of exploration expense." The remaining $1.0 million was classified as a reduction of McMoRan's leasehold costs in the specified nine prospects and is included within investing activities in the accompanying consolidated statement of cash flow. Drilling commenced during the fourth quarter on two prospects under this exploration agreement, Marlin at Grand Isle Block 18 and Hurricane Deep at South Marsh Island Block 217. The Marlin well reached its total planned depth and was determined to be nonproductive, resulting in a charge to exploration expense of $7.0 million representing McMoRan's net share of the costs incurred on the well through December 31, 2006. McMoRan announced a discovery at the Hurricane Deep well in late February 2007. Subsequently, two additional exploratory wells under this exploration agreement have commenced drilling, Cas at South Timbalier Block 70 on January 30, 2007 and Cottonwood Point at Vermilion Block 31 on March 1, 2007.

Multi-Year Exploration Program

In January 2004, McMoRan announced the formation of a multi-year exploration venture with a private exploration and production company (exploration partner). In October 2004, McMoRan announced an expanded exploration venture with its exploration partner with a joint commitment to spend at least $500 million to acquire and exploit high-potential prospects, primarily in Deep Miocene formations on the shelf of the Gulf of Mexico and in the Gulf Coast area. The spending commitments under the venture were achieved in 2006.

During the term of the exploration venture, McMoRan and its exploration partner generally shared equally in all future revenues and costs, including related overhead costs, associated with the exploration venture's activities, except for the Dawson Deep prospect at Garden Banks Block 625, where the exploration partner is participating in 40 percent of McMoRan's interests. McMoRan and the private partner will continue to participate jointly in the exploration venture's 14 discoveries as well as the wells not fully evaluated as discussed below. McMoRan's service revenues include management fees related to the exploration venture, which totaled $9.0 million in 2006 reflecting $8.0 million for 2006 activities and $1.0 million for services rendered during 2005. Service revenues related to the exploration venture totaled $7.0 million in 2005 and $12.0 million in 2004.

McMoRan and its exploration partner have participated in 14 discoveries on the 28 prospects that have been drilled and fully evaluated. Production has commenced on 13 discoveries and development plans are being pursued at the remaining discovery. McMoRan is testing and evaluating the Blueberry Hill at Louisiana State Lease 340. Information obtained from the Blueberry Hill well will be incorporated into the plan to evaluate the JB Mountain Deep well at South Marsh Island Block 224. At December 31, 2006, McMoRan's investments in the Blueberry Hill and JB Mountain Deep prospects totaled $16.5 million and $29.5 million, respectively.

Farm-out arrangement with El Paso Production Company

In May 2002, MOXY entered into a farm-out agreement with El Paso Production Company (El Paso) that provided for the funding of exploratory drilling and related development costs with respect to four of its prospects in the shallow waters of the Gulf of Mexico. Under the program, El Paso is funding all of MOXY's interests for the exploratory drilling and development costs of these prospects and will own 100 percent of the program's interests until aggregate production to the program's net revenue interests reaches 100 Bcfe. After aggregate production of 100 Bcfe, ownership of 50 percent of the program's interests would revert back to MOXY. El Paso drilled an exploratory well at each prospect, which yielded the initial discoveries at the JB Mountain prospect at South Marsh Island Block 223 in December 2002 and the Mound Point prospect at Louisiana State Lease 340 in April 2003. El Paso elected to relinquish its rights to the other two prospects where drilling resulted in a nonproductive exploratory well at each prospect. El Paso subsequently relinquished its rights to all but 13,000 gross acres surrounding the JB Mountain and Mound Point Offset wells. There are three

wells capable of production under this farm-out program. One of the wells is currently shut-in and remedial work is planned for the first quarter of 2007.

3. MAIN PASS ENERGY HUB™ PROJECT

Freeport Energy is pursuing alternative uses of its discontinued sulphur facilities at Main Pass in the Gulf of Mexico. Freeport Energy believes that an energy hub, consisting of facilities to receive and process LNG and store and distribute natural gas, could be developed at the facilities using the infrastructure previously constructed for its former sulphur mining operations. Freeport Energy refers to this project as the Main Pass Energy Hub™ project (MPEH™).

Freeport Energy has completed preliminary engineering for the development of MPEH™. In addition to completing a detailed engineering and financial assessment, certain regulatory approvals are required and the project will require significant financing. Applying for regulatory permits and pursuing commercial arrangements involves significant expenditures. Freeport Energy is seeking commercial arrangements to form the basis for financing the project. While there is no assurance that regulatory approvals and financing may be obtained at an acceptable cost, or on a timely basis, or at all, Freeport Energy's objective is to pursue both simultaneously in order to position this project to be one of the first U.S. offshore facilities to receive and process LNG and store and distribute natural gas.

Pursuant to the requirements of the U.S. Deepwater Port Act, Freeport Energy filed an initial application with the U.S. Coast Guard (Coast Guard) and the Maritime Administration (MARAD) in February 2004 requesting a license to develop the MPEH™ project. In May 2006, Freeport Energy filed an amended application with the Coast Guard and MARAD to develop an LNG receiving terminal at Main Pass using Closed Loop Technology. This action followed the veto by the Louisiana Governor of Freeport Energy's original application, which was seeking a permit using Open Rack Vaporizer technology.

In January 2007, MARAD approved Freeport Energy's license application for its MPEH™ project MARAD's approval and ultimate issuance of the Deepwater Port license for MPEH™ is subject to various terms, criteria and conditions contained in the Record of Decision, including demonstration of financial responsibility, compliance with applicable laws and regulations, environmental monitoring and other customary conditions.

The start-up costs associated with the establishment of the MPEH™ have been charged to expense in the accompanying consolidated statements of operations. These costs will continue to be charged to expense until permits are received and commercial feasibility is established, at which point Freeport Energy will begin to capitalize certain subsequent expenditures related to the development of the project. Freeport Energy incurred start-up costs for the MPEH™ project totaling $10.7 million in 2006 and $9.7 million in 2005. During 2004, MPEH™ project start-up costs totaled $11.5 million, including $0.2 million for warrants representing 25,000 shares of McMoRan common stock.

Currently, Freeport Energy owns 100 percent of the MPEH™ project. However, two entities have separate options to participate as passive equity investors for up to an aggregate 25 percent of Freeport Energy's equity interest in the project (*Notes 4 and 11*). Future financing and commercial arrangements may also reduce Freeport Energy's equity interest in the project.

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

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

	December 31,	
	2006	2005
Oil and gas property, plant and equipment	$ 521,372	$ 327,870
Other	31	56
	520,703	327,926
Accumulated depletion, depreciation and amortization	(238,865)	(135,529)
Property, plant and equipment, net	$ 282,538	$ 192,397

Reversionary Interests
In February 2002, McMoRan sold three oil and gas properties for $60.0 million and retained a reversionary interest equal to 75 percent of the transferred interests following payout of $60.0 million plus a specified annual rate of return. The three properties sold were Vermilion Block 196, Main Pass Block 86, and 80 percent of McMoRan's interest in Ship Shoal Block 296. During the first quarter of 2005, McMoRan reached agreement with the third-party purchaser to assign to McMoRan the 75 percent reversionary interest in Ship Shoal Block 296 effective February 1, 2005. Effective June 1, 2005, reversion of the interests in the other two properties occurred following payout.

Transactions Involving the Main Pass Oil Facilities
On December 16, 2002, McMoRan and K1 USA Energy Production Corporation (K1 USA), a wholly owned subsidiary of k1 Venture Limited (collectively K1), completed the formation of a joint venture, K-Mc I, owned 66.7 percent by K1 USA and 33.3 percent by McMoRan, which then acquired McMoRan's Main Pass oil facilities. Until December 27, 2004 (see below), K1 USA agreed to provide credit support for up to $10 million of bonding requirements with the MMS relating to the abandonment obligations for these facilities. McMoRan continued to operate the Main Pass facilities under a management agreement. The facilities not required to support the future planned business activities that now comprise the MPEH ™ project, were excluded from the joint venture and their dismantlement and removal is now substantially complete (Note 7). Proceeds for the joint venture's acquisition of the Main Pass oil facilities were funded in conjunction with McMoRan's funding requirements for the reclamation activities. See Note 11 for information concerning the settlement of litigation between a third-party contractor and McMoRan regarding the rights and obligations of both parties under the reclamation arrangements.

Prior to December 27, 2004 (see below), McMoRan accounted for its investment in the joint venture using the equity method (Note 1); however, McMoRan's investment (which had a zero basis at December 26, 2004) was limited to exclude recognition of negative investment in the joint venture as McMoRan was not required to fund joint ventures operating losses, debt or reclamation obligations.

Until September 2003, the joint venture also had an option to acquire from McMoRan the Main Pass facilities that will be used in the MPEH™ project (Note 3). In September 2003, McMoRan and K1 USA modified the joint venture transaction to eliminate that option, so that K1 USA now has the right to participate as a passive equity investor in up to 15 percent of McMoRan's equity participation in the MPEH™ project. K1 USA would need to exercise that right upon closing of the project financing arrangements by agreeing prospectively to fund up to 15 percent of McMoRan's future contributions to the project. K1 USA has received stock warrants to acquire a total of 2.5 million shares of McMoRan common stock at $5.25 per share, with the warrant for approximately 1.74 million shares expiring in December 2007 and the warrant for the remaining 0.76 million common shares expiring in September 2008. In addition to these stock warrants as of December 31, 2006, K1 owns 0.2 million shares of McMoRan's common stock and owns McMoRan convertible securities that can be converted into another 2.1 million shares of common stock.

On December 27, 2004, McMoRan acquired K1 USA's 66.7 percent interest in the joint venture, bringing McMoRan's ownership in the joint venture to 100 percent. McMoRan repaid the joint venture's debt totaling $8.0 million and released K1 USA from future abandonment obligations related to the facilities (Note 11). In the transaction McMoRan acquired $12.4 million of property, plant and equipment, $0.6 million of cash, $3.3 million of accounts receivable and $0.9 million of product inventory, and assumed $3.3 million of accounts payable and the $5.9 million estimated reclamation obligation associated with the Main Pass oil facilities.

The storm center of Hurricane Ivan passed within 20 miles east of Main Pass in September 2004. The Main Pass structures did not incur significant damage from Ivan but oil production was shut-in because of extensive damage to a third-party offshore terminal and connecting pipelines that provided throughput service for the sale of Main Pass sour crude oil. In May 2005 production resumed at Main Pass following successful modification of existing storage facilities to accommodate transportation of oil production from the field by barge. At December 31, 2006, McMoRan's property, plant and equipment included $8.2 million of costs associated with its efforts to modify these storage facilities. Insurance proceeds under McMoRan's business interruption and property insurance

policies partially mitigated the financial impact of the storm. The total of McMoRan's insurance proceeds related to its Ivan-related claims totaled $20.5 million, including $12.4 million of business interruption proceeds (of which $3.1 million was recorded as a reduction the cost of acquiring the joint venture), $0.6 million of reimbursements of other related expenditures and $7.5 million for costs related to the modification of the Main Pass facilities.

On August 29, 2005, the storm center of Hurricane Katrina passed within 50 miles west of Main Pass. While Main Pass facilities and platforms did not suffer significant damage from Katrina, oil operations were temporarily shut-in to perform required repairs resulting from the storm. Main Pass resumed oil production in late November 2005. Subsurface inspections at Main Pass that commenced in the fourth quarter of 2005 indicated the primary oil structures did not sustain any significant structural damage from the storm; but identified one ancillary structure that required repairs. As of December 31, 2006 these repair costs totaled $2.8 million. McMoRan is pursuing reimbursement of these costs under terms of its insurance policies. McMoRan has received $2.6 million of insurance proceeds under its insurance claims resulting from Hurricane Katrina.

The Main Pass oil lease was subject to a 25 percent overriding royalty retained by the original third-party owner after 36 million barrels of oil were produced, but subject to a 50 percent net profits interest. In February 2005, the original owner agreed to eliminate this royalty interest and McMoRan agreed to assume the owner's reclamation obligation associated with one platform and its related facilities located at Main Pass. McMoRan recorded $3.9 million to property, plant and equipment as well as accrued oil reclamation obligations related to the assumption of this liability pursuant to the requirements of SFAS 143. At December 31, 2006, McMoRan's estimated reclamation liability associated with its Main Pass oil facilities totaled $9.1 million. The amount of the ultimate estimated liability is $20.2 million on an undiscounted basis after adjusting for future inflation and applying a 10 percent market risk premium. As a result of this transaction, the original owner will be entitled to a 6.25 percent overriding royalty in any new wells drilled on the Main Pass oil lease.

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

	December 31,	
	2006	2005
Employee postretirement medical liability (Note 8)	$ 5,668	$ 4,812
Accrued workers compensation and group insurance	2,242	2,050
Sulphur-related environmental liability (Note 11)	3,161	3,161
Defined benefit pension plan liability (Note 8)	2,141	1,953
Nonqualified pension plan liability	1,012	849
Deferred compensation and other	208	346
Liability for management services (Note 10)	2,719	2,719
	$ 17,151	$ 15,890

The caption "Other assets" in the accompanying consolidated balance sheet includes deferred financing costs associated with the issuance of convertible debt and the establishment of a revolving credit facility (Note 5). Deferred financing costs for the 5¼% notes issued in 2004 totaled $5.7 million and are presented net of accumulated amortization of $2.5 million and $1.0 million at December 31, 2006 and 2005, respectively. Deferred financing costs associated with the 6% convertible debt issued in 2003 totaled $7.0 million and are shown net of amortization of $5.4 million and $3.5 million at December 31, 2006 and 2005, respectively. McMoRan's deferred financing costs related to its revolving credit facility totaled $0.5 million and are shown net of amortization of $0.1 million at December 31, 2006. As of December 31, 2006, McMoRan had incurred approximately $0.1 million of deferred financing costs for its term loan that was finalized in January 2007. Amortized deferred financing costs are charged to interest expense in the accompanying consolidated statements of operations.

5. LONG-TERM DEBT and EQUITY OFFERING

The table below contains the components of McMoRan's long-term debt, which is followed by additional disclosure of each component.

	December 31,	
	2006	2005
	(in thousands)	
6% convertible senior notes	$ 100,870	$ 130,000
5 ¼% convertible senior notes	115,000	140,000
Senior secured revolving credit facility	28,750	-
Long-term debt	$ 244,620	$ 270,000

5¼% Convertible Senior Notes and Equity Offering

On October 6, 2004, McMoRan completed two securities offerings with gross proceeds totaling $231 million. McMoRan issued approximately 7.1 million shares of its common stock at $12.75 per share. Net proceeds from the sale of common stock, after fees and expenses, totaled $85.5 million. McMoRan also completed a private placement of $140 million of 5¼% convertible senior notes due October 6, 2011. Net proceeds from the notes, after fees and expenses, totaled $134.4 million, of which $21.2 million was used to purchase U.S. government securities to be held in escrow to pay the first six semi-annual interest payments on the notes. The notes are otherwise unsecured. Interest payments are payable on April 6 and October 6 of each year, and began on April 6, 2005. McMoRan paid $6.0 million and $7.4 million of interest on these notes in 2006 and 2005, respectively. The notes are convertible at the option of the holder at any time prior to maturity into shares of McMoRan's common stock at a conversion price of $16.575 per share, representing a 30 percent premium over the $12.75 per share price at which McMoRan sold its common stock in the public offering. Beginning on October 6, 2009, McMoRan has the option of redeeming the notes for a price equal to 100 percent of the principal amount of the notes plus any accrued and unpaid interest on the notes prior to the redemption date, provided the closing price of McMoRan's common stock has exceeded 130 percent of the conversion price for at least 20 trading days in any consecutive 30-day trading period.

6% Convertible Senior Notes

On July 3, 2003, McMoRan issued $130 million of 6% convertible senior notes due July 2, 2008. Net proceeds from the notes totaled approximately $123.0 million, of which $22.9 million was used to purchase U.S. government securities held in escrow to secure the notes, and were used to pay the first six semi-annual interest payments through July 2, 2006. The notes are otherwise unsecured. Interest payments are payable on January 2 and July 2 of each year, and began on January 2, 2004. McMoRan paid $6.9 million of interest on the notes in 2006 and $7.8 million in both 2005 and 2004. The notes are convertible at the option of the holder at any time prior to maturity into shares of McMoRan's common stock at a conversion price of $14.25 per share, representing a 25 percent premium over the closing price for McMoRan's common stock on June 26, 2003.

Debt Conversion Transactions

In the first quarter of 2006, McMoRan privately negotiated transactions to induce conversion of $29.1 million of its 6% convertible senior notes and $25.0 million of its 5¼% convertible senior notes into approximately 3.6 million shares of its common stock based on the respective conversion price for each of the convertible notes. McMoRan paid an aggregate $4.3 million in the transactions and recorded an approximate $4.0 million net charge to expense in the first quarter of 2006. The net charge reflects the $4.3 million inducement payment, reflected in the accompanying consolidated statement of operations as other non-operating expense, less $0.3 million of previously accrued interest expense recorded during 2005. McMoRan funded approximately $3.5 million of the cash payments from restricted cash held in escrow for funding interest payments on the convertible notes and paid the remaining portion with available unrestricted cash. There were no induced conversion transactions during the remainder of 2006; however, one holder of the 6% Convertible Senior Notes converted $25,000 of the notes into 1,754 common stock shares.

Senior Secured Revolving Credit Facility

In April 2006, McMoRan established a new four-year, $100 million Senior Secured Revolving Credit Facility ("the facility") with a group of banks for use in MOXY's oil and natural gas operations. The facility

had an initial borrowing base of $55 million, which is redetermined each April 1 and October 1 based on MOXY's estimated oil and natural gas reserves. In October 2006, the lenders increased the facility's borrowing base to $70 million. The credit facility was amended upon the closing of a term loan agreement (see "Second Tier Term Loan" below) in January 2007 to reduce the borrowing base from $70 million to $50 million. The facility may be increased to $150 million with additional lender commitments. The facility matures on April 19, 2010. McMoRan's borrowings under the facility totaled $28.8 million at December 31, 2006. The weighted average interest rate on borrowings under the facility totaled 8.2 percent in 2006.

The variable-rate facility is secured by (1) substantially all the oil and gas related properties (and the related oil and natural gas proved reserves) of MOXY and (2) the pledge by McMoRan of its ownership interest in MOXY and by MOXY of its ownership interest in each of its wholly owned subsidiaries. The facility is guaranteed by McMoRan and each of MOXY's wholly owned subsidiaries and contains customary financial covenants and other restrictions.

Second Tier Term Loan

Effective January 19, 2007, MOXY entered into a Senior Term Loan Agreement (Term Loan). The loan agreement provides for a five-year, $100 million second lien senior secured term loan facility. Proceeds at closing, net of related fees and discounts, totaled approximately $98.0 million. McMoRan used the net proceeds to repay borrowings under the revolving credit facility ($46.4 million on January 20, 2007), and the remainder will be used to finance MOXY's future exploration and development activities, working capital requirements and for general corporate purposes. The obligations under the term loan are guaranteed by McMoRan and each of MOXY's wholly owned subsidiaries.

The term loan contains customary financial covenants and other restrictions. A annual mandatory $10 million payment of principal is due each December 31 commencing on December 31, 2008. Amounts borrowed under the term loan agreement bear interest, at MOXY's option, at an annual rate equal to either (1) the higher of the lenders' prime rate or the federal funds effective rate, plus 0.5 percent, plus 6.0 percent or (2) the rate at which eurodollar deposits in the London interbank market for one, two, three or six months (as selected by MOXY) are quoted on the Telerate screen, as adjusted for actual statutory reserve requirements for eurocurrency liabilities, plus 7.0 percent. Payment of interest is due on at least a quarterly basis.

Optional prepayments of the term loan are subject to a prepayment premium of 3.0 percent through January 19, 2008, 2.0 percent through January 19, 2009, and 1.0 percent through January 19, 2010. Optional prepayments made after January 19, 2010 are not subject to prepayment premiums. Repayments under the term loan can be accelerated by the lenders upon the occurrence of customary events of default. The term loan will mature on January 19, 2012.

6. MANDATORILY REDEEMABLE PREFERRED STOCK

In June 2002, McMoRan completed a $35 million public offering of 1.4 million shares of its 5% mandatorily redeemable convertible preferred stock. Proceeds received from this offering totaled $33.7 million, net of an underwriting discount of $1.1 million and $0.2 million of other issuance costs. Each share provides for a quarterly cash dividend of $0.3125 per share ($1.25 per share annually) and is convertible at the option of the holder at any time into 5.1975 shares of McMoRan's common stock, which is equivalent to $4.81 per common share, representing a 20 percent premium over McMoRan's common stock closing price on June 17, 2002. During 2006, 1,600 shares of the convertible stock were tendered and converted into 8,316 shares of McMoRan common stock. During 2005, 28,775 shares of the convertible preferred stock were tendered and converted into approximately 0.1 million shares of McMoRan common stock. During 2004, 45,185 shares of the convertible preferred stock were tendered and converted into approximately 0.2 million shares of McMoRan common stock. McMoRan may redeem the preferred stock after June 30, 2007 and must redeem the stock by June 30, 2012. Any redemption by McMoRan must be made in cash. McMoRan accrued to expense preferred dividends totaling $1.5 million in each of the three years ended December 31, 2006. Accumulated amortization of the convertible preferred stock issuance costs totaled $0.6 million at December 31, 2006 and $0.4 million at December 31, 2005.

7. DISCONTINUED OPERATIONS

In November 1998, McMoRan acquired Freeport Sulphur (now Freeport Energy), a business engaged in the purchasing, transporting, terminaling, processing, and marketing of recovered sulphur and the production of oil reserves at Main Pass. Prior to August 31, 2000, Freeport Sulphur was also engaged in the 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. All of McMoRan sulphur results are included in the accompanying consolidated statements of operations within the caption "(Loss) income from discontinued operations."

The table below provides a summary of the discontinued results of operations (amounts in thousands):

	Years Ended December 31,		
	2006	2005	2004
Sulphur retiree costs [a]	(1,436)	(2,513)	(2,777)
Legal expenses	126	387	1,629 [b]
Caretaking costs	1,889	1,476	1,055
Accretion expense – sulphur reclamation obligations [c]	4,417 [d]	7,205 [e]	634
Insurance	881	1,030	(384) [f]
General and administrative	50	196	284
Other	(2,989) [g]	461 [h]	(802) [i]
Loss (income) from discontinued operations	$ 2,938	8,242	(361)

a. Reflects postretirement benefit costs associated with certain retired former sulphur employees (Note 11). Amount during 2006 reflects $3.2 million reduction in a contractual liability resulting primarily from a significant reduction in the number of participants in the related benefit plans. The contractual liability was reduced by $3.5 million at year end 2005 to reflect the expected future benefit associated with the initiation of the federal prescription drug program. The 2004 amount reflected a $5.2 million reduction in a contractual liability reflecting a decrease in the number of participants in the plans and certain plan amendments made by the plan sponsor.
b. Reflects the costs associated with litigation involving reclamation activities at Main Pass. The case was settled in July 2004 (see "Sulphur Reclamation Obligations" below).
c. Reflects adoption of SFAS 143 "Accounting for Asset Retirement Obligations" on January 1, 2003 (Note 11).
d. Includes a $3.4 million charge to expense at December 31, 2006 to increase the accrued reclamation costs for the Port Sulphur facilities to their estimated fair value. The increased estimate incorporates the planned acceleration of certain of these closure costs as well as higher costs associated with a portion of the facilities.
e. Includes a $6.5 million charge to expense in fourth quarter of 2005 reflecting a modification of McMoRan's prior reclamation plan for its remaining facilities at Port Sulphur.
f. During 2004, McMoRan reduced its estimated uninsured workers compensation and general liability claims following completion of an analysis of such matters resulting in a $0.8 million reduction in the related accrued liability.
g. Includes income of $3.5 million related to approved insurance claims resulting from property damages at the Port Sulphur facilities. Also includes $0.5 million of additional hurricane repair costs.
h. Includes approximately $0.5 million of repair and related costs for the Port Sulphur facilities following Hurricanes Katrina and Rita.
i. Includes $0.3 million gain on the sale of material and supplies inventory that was charged to expense in June 2000, $0.3 million from the remediation of an environmental liability previously assumed (Note 11) and $0.2 million of sublease income from the sulphur railcars during the first quarter of 2004.

Exit From Sulphur Business

In July 2000, McMoRan undertook a plan to exit its sulphur mining operations conducted at its offshore mining facilities at Main Pass and to sell its sulphur transportation and terminaling assets. The Main Pass sulphur mine ceased production on August 31, 2000. McMoRan sold its sulphur transportation and terminaling assets in June 2002 for $58 million in gross proceeds.

In connection with the sale, McMoRan also agreed to be responsible for certain historical environmental obligations relating to its former sulphur transportation and terminaling assets and also agreed to indemnify the purchaser from certain potential 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 the purchaser from, certain potential obligations, including environmental obligations, other than liabilities existing and identified as of the closing of the sale, associated with historical oil and gas operations undertaken by the Freeport-McMoRan companies prior to the 1997 merger of Freeport-McMoRan Inc. and IMC Global Inc. As of December 31, 2006, McMoRan has paid approximately $0.2 million to settle certain claims associated with these assumed historical environmental obligations (Note 11).

Sulphur Reclamation Obligations
McMoRan is currently meeting its financial obligations relating to the future abandonment of its Main Pass facilities with the MMS using financial assurances from MOXY. McMoRan and its subsidiaries' ongoing compliance with applicable MMS requirements will be subject to meeting certain financial and other criteria.

In 2002, McMoRan entered into turnkey contracts with Offshore Specialty Fabricators Inc. (OSFI) to dismantle and remove the remaining Main Pass and Caminada sulphur facilities. OSFI completed its reclamation activities at the Caminada mine site in 2002 and commenced its reclamation work at the facilities not essential to any future business activities at Main Pass, which is now substantially complete. McMoRan paid OSFI $13 million for the removal of these structures at Main Pass. The remaining $2.6 million amount related to this reclamation obligation is included in both discontinued current assets and current liabilities in the accompanying consolidated balance sheets at December 31, 2006 and 2005. See Note 11 regarding the settlement of litigation between McMoRan and OSFI.

8. EMPLOYEE BENEFITS

Stock-Based Awards. At December 31, 2006, McMoRan had eight shareholder-approved stock incentive or stock option plans. The plans are authorized to issue a fixed amount of stock-based awards, which include stock options, stock appreciation rights and restricted stock units (RSUs) that are issuable in 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. Below is a summary of McMoRan's plans.

Plan	Authorized amount of stock-based awards	Shares available for grant at December 31, 2006
2005 Stock Incentive Plan ("the 2005 Plan")	3,500,000	1,335,500
2004 Director Compensation Plan ("2004 Directors Plan")	175,000	140,272
2003 Stock Incentive Plan ("the 2003 Plan")	2,000,000	-
2001 Stock Incentive Plan ("the 2001 Plan")	1,250,000	2,000
2000 Stock Option Plan ("the 2000 Plan")	600,000	1,000
1998 Stock Option Plan ("the 1998 Plan")	775,000	4,500
1998 Stock Option Plan for Non Employee Directors (the Directors Plan")	75,000	24,375
1998 Adjusted Stock Award Plan	794,250	-

For information regarding McMoRan's RSUs see Note 1 – "Restricted Stock Units." McMoRan did not have any stock appreciation rights outstanding at December 31, 2006. A summary of stock options outstanding follows:

	2006		2005		2004	
	Number of Options	Average Option Price	Number of Options	Average Option Price	Number of Options	Average Option Price
Beginning of year	5,845,416	14.57	4,820,860	$13.97	4,069,572	$13.50
Granted	1,365,500	19.79	1,310,500	16.74	996,092	16.63
Exercised	(26,823)	14.52	(255,699)	13.32	(82,220)	13.08
Expired/forfeited	(88,102)	20.71	(30,245)	22.25	(162,584)	18.97
End of year	7,095,991	15.50	5,845,416	14.57	4,820,860	13.97
Exercisable at end of year	5,169,822		4,167,393		3,401,607	

The Co-Chairmen of McMoRan's Board of Directors agreed to forgo all cash compensation during each of the three years ended December 31, 2006. In lieu of cash compensation, McMoRan has granted the Co-Chairmen stock option grants that are immediately exercisable upon grant and have a term of ten years. These grants to the Co-Chairmen totaled 500,000 options at an exercise price of $19.85 per share in January 2006, 500,000 options at an exercise price of $16.65 per share in January 2005 and 300,000 options at an exercise price of $16.78 per share in February 2004. The Co-Chairmen also received additional grants totaling 350,000 stock options in January 2006, 350,000 stock options in January 2005 and 225,000 stock options in February 2004, all of which vest ratably over a four-year period.

On January 31, 2005, McMoRan's Board of Directors granted 452,500 stock options, including immediately exercisable options for 255,000 shares to its Co-Chairmen. Options for 813,500 additional shares, including immediately exercisable options for 245,000 shares to McMoRan's Co-Chairmen, were also granted on this date but their issuance was contingent on shareholder approval of the 2005 Stock Plan, which occurred on May 5, 2005. All other stock options granted on January 31, 2005 become exercisable over a four-year period. Pursuant to accounting requirements of APB Opinion No. 25 (see Note 1 – "Stock Based Compensation Costs"), the $1.51 per share difference between the market price on January 31, 2005 ($16.65 per share) and the market price on May 5, 2005 ($18.16 per share) was charged to earnings as the options vested. In May 2005, McMoRan recorded noncash compensation charges of $0.4 million related to the immediately exercisable options granted to the Co-Chairmen.

In February 2003, McMoRan's Board of Directors approved the grant of options to purchase 737,500 shares of McMoRan common stock at $7.52 per share from the 2003 Plan. The 2003 Plan, including grants to the Co-Chairmen, was subject to shareholder approval, which occurred at McMoRan's annual shareholders' meeting on May 1, 2003. Pursuant to accounting requirements, the $4.99 per share difference between the market price when the Board approved the grants and the market price on May 1, 2003 ($12.51 per share) was charged to earnings as the options vested.

For additional information regarding stock based compensation costs for the three years ended December 31, 2006 see Note 1 – "Stock Based Compensation Costs". A summary of stock-based compensation for the three years ended December 31, 2006 is as follows:

	2006	2005	2004
General and administrative expenses	$ 7,120	$ 615	$ 405
Exploration expenses	8,104	1,052	702
Main Pass Energy Hub start-up costs	598	10	-
Total stock-based compensation cost	$ 15,822	$ 1,677	$ 1,107

Pension Plans and Other Benefits. During 2000, McMoRan elected to terminate its defined benefit pension plan covering substantially all its employees and replace this plan with a defined contribution plan, as further discussed below. All participants' account balances in the defined benefit plan were fully vested on June 30, 2000. The plans' investment portfolio was liquidated and invested primarily in short duration fixed-income securities in the fourth quarter of 2000 to reduce exposure to equity market volatility. Interest credits will continue to accrue under the plan until the assets are liquidated, which will occur once approval is obtained from the Internal Revenue Service and the Pension Benefit Guaranty Corporation. Upon receiving this approval, McMoRan will make the final distribution of the participants' account balances,

which will require McMoRan to fund any shortfall between these obligations and the plan assets. At December 31, 2006, the plan's assets had a fair value of $2.2 million and the shortfall approximated $2.1 million. In 2005, McMoRan fully funded its approximate $0.5 million portion of the pension obligation associated with employees of FM Services Company (FM Services) (Note 10).

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. For the year ended December 31, 2006, the health care trend rate used for Other Benefits was 9 percent in 2007, decreasing ratably annually until reaching 5 percent in 2011. For the year ended December 31, 2005, the health care cost trend rate used for the Other Benefits was 10 percent in 2006, decreasing ratably annually until reaching 5.0 percent in 2011. A one-percentage-point increase or decrease in assumed health care cost trend rates would not have a significant impact on service or interest costs. Information on the McMoRan plans follows (dollars in thousands):

	Pension Benefits		Other Benefits	
	2006	2005	2006	2005
Change in benefit obligation:				
Benefit obligation at the beginning of year	$ (4,502)	$ (5,145)	$ (6,300)	$ (6,179)
Service cost	-	-	(20)	(19)
Interest cost	(217)	(243)	(347)	(358)
Change in Plan payout assumptions	-	-	-	369
Actuarial gains (losses)	-	-	108	(596)
Participant contributions	-	-	(207)	(153)
Benefits paid	347	886	473	636
Benefit obligation at end of year	(4,372)	(4,502)	(6,293)	(6,300)
Change in plan assets:				
Fair value of plan assets at beginning of year	2,549	3,339	-	-
Return on plan assets	29	96	-	-
Employer/participant contributions	-	-	473	636
Benefits paid	(347)	(886)	(473)	(636)
Fair value of plan assets at end of year	2,231	2,549	-	-
Funded status	$ (2,141)	$ (1,953)	$ (6,293)	$ (6,300)
Weighted-average assumptions (percent):				
Discount rate	N/A[a]	N/A[a]	5.75	5.5
Expected return on plan assets	N/A	N/A	-	-
Rate of compensation increase	N/A	N/A	-	-

a. As discussed above, McMoRan elected to terminate its defined benefit pension plan on June 30, 2000. McMoRan invests almost the entire amount of its plan asset portfolio in short-term fixed income securities, with the remainder invested in overnight money market accounts.

Expected benefit payments for McMoRan's other benefits plan total $0.6 million in both 2007 and 2008, $0.7 million in each year ending December 31, 2009, 2010 and 2011, and a total of $2.7 million during 2012 through 2016. The components of net periodic benefit cost for McMoRan's plans follow (in thousands):

	Pension Benefits			Other Benefits		
	2006	2005	2004	2006	2005	2004
Service cost	$ -	$ -	$ -	$ 20	$ 19	$ 21
Interest cost	217	243	334	347	358	378
Return on plan assets	(29)	(96)	(145)	-	-	-
Amortization of prior service costs	-	-	-	(40)	(47)	(13)
Recognition of net actuarial loss	-	-	-	148	114	95
Net periodic benefit cost	$ 188	$ 147	$ 189	$ 475	$ 444	$ 481

Included in accumulated other comprehensive loss at December 31, 2006 (Note 1), are the following amounts that have not been recognized in net periodic benefit costs associated with McMoRan's health care and life insurance benefits for its retired employees (Other Benefits): unrecognized prior service credits of $0.3 million and unrecognized actuarial losses of $1.6 million. The total amount expected to be recognized into net periodic costs in 2007 associated with these prior service credits and actuarial gains and losses is $0.1 million.

McMoRan has an employee savings plan under Section 401(k) of the Internal Revenue Code. The plan allows eligible employees to contribute up to 50 percent of their pre-tax compensation, subject to a limit prescribed by the Internal Revenue Code, which was $15,000 for 2006, $14,000 for 2005 and $13,000 for 2004. McMoRan matches 100 percent of each employees' contribution up to a maximum of 5 percent of the each employees' annual basic compensation amount. As a result of McMoRan's decision to terminate its defined benefit pension plan effective July 1, 2000, McMoRan fully vested all active Section 401(k) savings plan participants on June 30, 2000. Subsequently, all new plan participants will vest in McMoRan's matching contributions upon three years of service with McMoRan. Additionally, McMoRan established a defined contribution plan for substantially all its employees. Under this plan, McMoRan contributes amounts to individual employee accounts totaling either 4 percent or 10 percent of each employee's pay, depending on a combination of each employee's age and years of service with McMoRan. McMoRan charged $0.5 million in 2006, $0.4 million in 2005 and $0.3 million in 2004 to its results of operations for the Section 401(k) savings plan and the defined contribution plan. Additionally, McMoRan has other employee benefit plans, certain of which are related to McMoRan's performance, which costs are recognized currently in general and administrative expense.

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

9. INCOME TAXES

McMoRan accounts for income taxes pursuant to SFAS 109, "Accounting for Income Taxes." McMoRan has a net deferred tax asset of $232.1 million as of December 31, 2006, resulting from net operating loss carryforwards and other temporary differences related to McMoRan's activities. McMoRan has provided a valuation allowance, including approximately $32.7 million associated with McMoRan's discontinued sulphur operations, for the full amount of these net deferred tax assets. The components of McMoRan's net deferred tax asset at December 31, 2006 and 2005 follow (in thousands):

	December 31,	
	2006	2005
Net operating loss carryforwards (expire 2007-2026)	$ 158,360	$ 155,490
Property, plant and equipment	35,931	30,330
Reclamation and shutdown reserves	18,073	13,662
Deferred compensation, postretirement and pension benefits and accrued liabilities	13,827	9,170
Other	5,940	6,449
Less valuation allowance	(232,131)	(215,101)
Net deferred tax asset	$ -	$ -

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

	2006		2005		2004	
	Amount	Percent	Amount	Percent	Amount	Percent
Income tax benefit computed at the federal statutory income tax rate	$ 16,679	35%	$ 13,899	35%	$ 18,085	35%
Change in valuation allowance	(17,030)	(36)	(9,951)	(25)	(17,664)	(35)
Other	351	1	(3,948)[a]	(10)	(421)	-
Income tax provision	$ -	- %	$ -	- %	$ -	- %

a. Amount primarily reflects the $12.8 million litigation settlement charge, which is not deductible for income tax purposes.

10. TRANSACTIONS WITH AFFILIATES

FM Services, a company in which McMoRan shares certain common executive management, provides McMoRan with certain administrative, financial and other services on a contractual basis. These service costs, which include related overhead amounts, totaled $5.2 million in 2006, $5.3 million in 2005 and $4.0 million in 2004. 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. At December 31, 2006 and 2005, McMoRan had an obligation to fund $2.7 million of FM Services costs, primarily reflecting long-term employee pension and postretirement medical obligations (Notes 4 and 8). In 2005, McMoRan paid its approximate $0.5 million obligation related to FM Services' defined benefit plan, which was terminated effective June 30, 2000.

11. COMMITMENTS AND CONTINGENCIES

Commitments. McMoRan plans to participate in the drilling of 8-10 exploratory wells during 2007. At December 31, 2006, McMoRan had a $47.3 million of contractual commitments related to its planned oil and gas activities, including costs related to projects currently in progress, inventory purchase commitments and other exploration expenditures. McMoRan also has an exclusive contract with a third party to identify and evaluate oil and gas exploration prospects until March 2009. For these services, the third party is paid $0.4 million annually and is entitled to an overriding royalty interest in prospects presented and accepted by McMoRan. The amount of the overriding royalty interest is predicated on the size of McMoRan's working interest in the property and will not exceed 0.5 percent in any prospect accepted by McMoRan.

Long-Term Contracts and Operating Leases. McMoRan's primary operating lease involves renting office space in Houston, Texas, which expires in April 2009. In January 2004, McMoRan terminated its sulphur railcar lease, which was originally scheduled to expire in March 2011, by paying the owner $7.0 million and sold the railcars to a third party for $1.1 million. At December 31, 2006, McMoRan's total minimum annual contractual charges aggregate $0.5 million, with $0.2 million payable in 2007.

Other Liabilities. Freeport Energy has a contractual obligation to reimburse a third party portion of its postretirement benefit costs relating to certain retired former sulphur employees of Freeport Energy. This contractual obligation totaled $10.6 million at December 31, 2006 and $15.0 million at December 31, 2005, including $2.1 million and $3.5 million in current liabilities from discontinued operations, respectively. McMoRan's actuarial consultant reviews the estimated related future costs associated with this contractual liability on an annual basis using current health care trend costs and incorporates changes made to the underlying benefit plans of the third party. The assessment at year end 2006 used an initial health care cost trend rate of 9 percent in 2007 decreasing ratably to 5 percent in 2011. During 2005, the assessment used an initial health care cost trend rate of 10 percent in 2006 decreasing ratably to 5 percent in 2011. McMoRan applied a discount rate of 7.5 percent at December 31, 2006 and 7.0 percent at December 31, 2005 to the consultant's future cost estimates. McMoRan reduced the liability by $3.2 million at December 31, 2006 to reflect a significant decrease in the number of participants covered by the related benefit plans associated with this contractual liability. McMoRan reduced the liability by $3.5 million at December 31, 2005 to reflect future estimated benefits associated with the

federal subsidy of certain prescription drug costs as allowed for under the Medicare Prescription Drug Program as well as other actuarial assumptions regarding the mortality rates to apply against the plan's population. 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 Energy placed $3.5 million in an escrow account to fund certain assumed sulphur-related environmental liabilities. During 2004, McMoRan preformed remediation work for one of the assumed liabilities and the related $0.3 million of the related escrowed funds was released. At December 31, 2006 and 2005, McMoRan had $3.2 million remaining in escrow related to these assumed environmental liabilities. The restricted escrowed funds, which approximate McMoRan's estimated costs for the assumed environmental liabilities, is classified as a long-term asset and recorded in "Restricted investments and cash", with a corresponding amount recorded in "Other Liabilities" in the accompanying consolidated balance sheets.

Environmental and Reclamation. McMoRan has made, and will continue to make, expenditures for the protection of the environment. McMoRan is subject to contingencies as a result of environmental laws and regulations. Present and future environmental laws and regulations applicable to McMoRan's operations could require substantial capital expenditures or could adversely affect its operations in other ways that cannot be predicted at this time. See Note 7 for further information about McMoRan's efforts to resolve its sulphur reclamation obligations with the MMS and it assuming potential obligations in connection with the sale of its sulphur transportation and terminaling assets. As of December 31, 2006, McMoRan has paid approximately $0.2 million to settle certain claims related to historical oil and gas liabilities it assumed from IMC Global. No additional amounts have been recorded because no specific liability has been identified that is reasonably probable of requiring McMoRan to fund any future material amounts.

Effective January 1, 2003, McMoRan adopted SFAS No. 143 (Note 1). At December 31, 2006 and 2005, McMoRan revised its reclamation and well abandonment estimates for (1) changes in the projected timing of certain reclamation costs because of changes in the estimated timing of the depletion of the related proved reserves for McMoRan's oil and gas properties and new estimates for the timing for the reclamation of the structures comprising the MPEH™ project and Port Sulphur facilities; (2) changes in its credit-adjusted risk free interest rate; and (3) assuming additional obligations at some properties and recording obligations relating to any new properties. McMoRan's credit adjusted, risk-free interest rates ranged from 9.33 percent to 10 percent at December 31, 2006, 8.35 percent to 10 percent at December 31, 2005 and 6.25 percent to 10 percent at December 31, 2004. At December 31, 2006, McMoRan's estimated undiscounted reclamation obligations, including inflation and market risk premiums, totaled $83.8 million, including $42.2 million associated with its remaining sulphur obligations. A rollforward of McMoRan's consolidated discounted asset retirement obligations follow (in thousands):

	Years Ended December 31,		
	2006	2005	2004
Oil and Natural Gas			
Asset retirement obligation at beginning of year	$ 21,760	$ 14,429	$ 7,273
Liabilities settled	(670)	(4)	(288)
Accretion expense [a]	2,088 [b]	1,442	487
Incurred liabilities	2,534 [c]	6,978 [f]	6,399 [g]
Revision for changes in estimates	164	(1,085)	558
Asset retirement obligations at end of year	$ 25,876	$ 21,760	$ 14,429
Sulphur			
Asset retirement obligations at beginning of year:	$ 21,786	$ 14,636	$ 14,001
Liabilities settled	(3,109) [d]	(55)	-
Accretion expense	1,392	960	868
Revision for changes in estimates	3,025 [e]	6,245 [e]	(233)
Asset retirement obligation at end of year	$ 23,094	$ 21,786	$ 14,636

a. Accretion expense charges are included within depletion, depreciation and amortization expense in the accompanying consolidated statements of operations.
b. Includes $0.7 million charge for the remaining estimated reclamation costs for the West Cameron Block 43 field (Note 1).
c. Reflects reclamation obligations associated with discoveries and additional development wells that commenced production in 2006.

d. Amount of costs incurred to remove structures at Port Sulphur that were damaged by hurricanes Katrina and Rita in 2005.
e. Revisions primarily reflect changes in estimated timing of reclamation work at Port Sulphur (Note 7). Accretion expense within discontinued operations includes amounts associated with revision for changes in estimates because there are no related property, plant and equipment amounts associated with the sulphur reclamation obligations.
f. Includes $3.9 million reclamation liability assumed in connection with the termination of the overriding royalty interest in Main Pass' oil production (Note 4). Also includes $2.2 million of assumed reclamation liabilities related to interests in properties which reverted to McMoRan effective June 1, 2005 (Note 4). The remaining amount reflects estimated reclamation liabilities associated with our discoveries that commenced production in 2005.
g. Includes $5.9 million assumed liability related to McMoRan's acquisition of the 66.7 percent third-party ownership interest in the joint venture for the Main Pass oil operations (Note 4).

Litigation. In 2002, McMoRan entered into a turnkey contract with OSFI for the reclamation of the sulphur mine and related facilities at Main Pass located offshore in the Gulf of Mexico. OSFI substantially completed its reclamation work at Main Pass for the structures not essential for use in the MPEH™ project. However, a contractual dispute between the parties resulted in litigation which was settled in July 2004. In accordance with the settlement, OSFI will complete the remaining reclamation work and McMoRan paid OSFI the $2.5 million representing the final balance for these reclamation costs in November 2004. In addition, OSFI currently has no obligation regarding the MPEH™ structures. Pursuant to the settlement, OSFI was granted an option to participate in the MPEH™ project for up to 10 percent of McMoRan's equity interest on a basis parallel to McMoRan's agreement with K1 USA (Note 4).

In December 2005, McMoRan reached an agreement in principle with plaintiffs to settle previously disclosed litigation in the Delaware Court of Chancery relating to the 1998 merger of Freeport-McMoRan Sulphur Inc. and McMoRan Oil & Gas Co. McMoRan paid $17.5 million in cash into a settlement fund in the first quarter of 2006, the plaintiffs provided a complete release of all claims, and the Delaware litigation was dismissed with prejudice. During the fourth quarter of 2005, McMoRan recorded a $12.8 million charge, net of the minimum amount of insurance proceeds agreed to by insurers, for the settlement of this litigation. McMoRan received an additional $0.4 million of insurance proceeds in 2006. These items are disclosed as a separate line item in the accompanying consolidated statements of operations.

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 offshore in the Gulf of Mexico and onshore in the Gulf Coast region 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,	
	2006	2005
	(In Thousands)	
Unproved properties [a]	$ 45,237	$ 36,429
Proved properties [b]	476,135	291,441
Subtotal	521,372	327,870
Less accumulated depreciation and amortization	(238,865)	(135,529)
Net oil and gas properties	$ 282,507	$ 192,341

a. Includes costs associated with in-progress wells and wells not fully evaluated, including related leasehold acquisition costs, totaling $38.4 million at December 31, 2006 and $21.1 million at December 31, 2005.
b. Includes the costs associated with the Blueberry Hill well at Louisiana State Lease 340 which is awaiting final testing and completion activities. Amounts totaled $16.5 million at December 31, 2006 and $11.2 million at December 31, 2005.

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

	Years Ended December 31,		
	2006	2005	2004
	(In Thousands)		
Acquisition of properties:			
Proved	$ -	$ -	$ 12,375[a]
Unproved	2,310	3,542	3,808
Exploration costs	124,590	88,294	92,473
Development costs	134,338	90,617	5,408
	$ 261,238	$ 182,453	$ 114,064

a. Amount reflects the acquisition in December 2004 of the remaining 66.7 percent equity interest in the joint venture associated with the Main Pass oil operations (Note 4).

The following table reflects the net changes in McMoRan's capitalized exploratory well costs (excluding any related leasehold costs) during each of the three years ended December 31, 2006.

	Years Ended December 31,		
	2006	2005	2004
Beginning of year	$ 19,619	$ 39,270	$ 2,082
Additions to capitalized exploratory well costs pending determination of proved reserves	242,558	163,638	77,807
Reclassifications to wells, facilities, and equipment based on determination of proved reserves	(178,777)	(136,465)	(19,249)
Amounts charged to exploration expense	(44,944)	(46,824)	(21,370)
End of year	$ 38,456	$ 19,619	$ 39,270

At December 31, 2005, McMoRan had investments in two wells that had been capitalized for a period in excess of one year following the completion of the drilling of each well. These investments were in the Garden Banks Block 625 (Dawson Deep) and the Louisiana State Lease 340 (Blueberry Hill) wells. Both the Dawson Deep and Blueberry Hill wells were assigned proved reserves by Ryder Scott Company, L.P. (Ryder Scott), an independent petroleum engineering firm, at December 31, 2005. In January 2006, completion activities commenced at the Dawson Deep well and the well commenced production in July 2006. McMoRan received the specialized equipment necessary for the completion of the Blueberry Hill in the second half of 2006 and is currently evaluating and testing the well. Completion operations at Blueberry Hill are expected to commence following a successful test of the well. McMoRan's net investment in the Blueberry Hill well totaled $16.5 million at December 31, 2006 and $11.2 million at December 31, 2005.

Proved Oil and Natural Gas Reserves (Unaudited). Proved oil and natural gas reserves for each of the three years ending December 31, 2005 have been estimated by Ryder Scott, in accordance with guidelines established by the Securities and Exchange Commission (SEC), which require such estimates to be based upon existing economic and operating conditions as of year-end without consideration of expected changes in prices and costs or other future events. All estimates of oil and natural 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 natural 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 (MBbls) and natural gas in millions of cubic feet (MMcf).

	Oil			Natural Gas		
	2006	2005	2004	2006	2005	2004
Proved reserves:						
Beginning of year	7,131	4,789	547	38,944	21,187	13,567
Revisions of previous estimates	(343)	1,137	96	(349)	(2,150)	833
Discoveries and extensions	536	1,602[b]	112[c]	17,153	27,845[b]	10,720[c]
Production	(1,552)	(850)	(62)	(14,546)	(7,938)	(1,979)
Sale of reserves	-	-	(66)	-	-	(2,236)
Purchase of reserves	-	453[d]	4,162[e]	-	-	282
End of year	5,772[a]	7,131	4,789	41,202[f]	38,944	21,187
Proved developed reserves:						
Beginning of year	6,248	4,640	389	29,101	14,765	8,074
End of year	5,526[a]	6,248	4,640	34,949[f]	29,101	14,765

a. Includes approximately 46 MBbls of oil associated with the West Cameron Block 43 field that McMoRan currently believes will not be recoverable (Note 1).
b. The estimated proved reserves include 3,363 MMcf of natural gas and 80 MBbls of oil associated with the reversions of interest to McMoRan from properties it sold in 2002 (Note 4).
c. Amount includes 2,587 MMcf of natural gas related to McMoRan's elections at the West Cameron Block 616 field following payout of the field in September 2004 (Note 4).
d. In February 2005, McMoRan negotiated the termination of an overriding royalty/net profit interest in the oil production at Main Pass by assuming a reclamation obligation at the field (Notes 4 and 11).
e. Represents McMoRan's acquisition of the remaining 66.7 percent equity ownership of K-Mc I, which owns the oil operations at Main Pass (Note 4).
f. Includes 1,129 MMcf of natural gas associated with the West Cameron Block 43 field that McMoRan currently believes will not be recoverable (Note 1).

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

McMoRan's standardized measure of discounted future net cash flows and changes therein relating to proved oil and natural gas reserves were computed using reserve valuations based on regulations and parameters prescribed by the SEC. These regulations require the use of year-end oil and natural gas prices in the projection of future net cash flows. The weighted average of these prices for all properties with proved reserves was $53.56 per barrel of oil and $6.08 per Mcf of natural gas at December 31, 2006 and $54.03 per barrel of oil and $10.35 per Mcf of natural gas at December 31, 2005. The oil price reflects the lower market value associated with the sour crude oil reserves produced at Main Pass, whose year-end prices were $51.77 per barrel at December 31, 2006 and $52.11 per barrel at December 31, 2005.

	December 31,	
	2006	2005
	(In Thousands)	
Future cash inflows	$ 560,852	$ 789,503
Future costs applicable to future cash flows:		
Production costs	(199,246)	(226,668)
Development and abandonment costs	(46,591)	(79,077)
Future income taxes	(772)	(6,765)
Future net cash flows	314,243[a]	476,993
Discount for estimated timing of net cash flows (10% discount rate)[b]	(44,281)	(93,854)
	$ 269,962[a]	$ 383,139

a. Amount includes $7.9 million of estimated undiscounted future net cash flows and $6.9 million of estimated discounted future cash flows associated with proved reserves attributable to the West Cameron Block 43 field that McMoRan currently believes will not be recoverable (Note 1).
b. Amount reflects application of required 10 percent discount rate to both the estimated future income taxes and estimated future net cash flows associated with production of the estimated proved reserves.

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

	Years Ended December 31,		
	2006	2005	2004
	(In Thousands)		
Beginning of year	$ 383,139	$ 117,289	$ 52,702
Revisions:			
Changes in prices	(106,961)	70,657	6,271
Accretion of discount	38,313	11,729	5,270
Change in reserve quantities	(21,317)	(15,051)	3,205
Other changes, including revised estimates of development costs and rates of production	(11,739)	9,204	(5,967)
Discoveries and extensions, less related costs	93,125	257,432[a]	59,195[b]
Development costs incurred during the year	35,123	8,640	2,112
Change in future income taxes	3,862	(4,445)	-
Revenues, less production costs	(143,583)	(88,607)	(10,126)
Sale of reserves in place	-	-	(11,477)
Purchase of reserves in place	-	16,291[c]	16,104[d]
End of year	$ 269,962	$ 383,139	$ 117,289

a. Amount includes $65.5 million relating to the reversion of interests to McMoRan in properties it sold in February 2002 (Note 4).
b. Amount also includes $13.2 million relating to McMoRan's elections associated with the West Cameron Block 616 field in September 2004 (Note 4).
c. Reflects the termination of an overriding royalty/net profit interest in the oil production at Main Pass (Note 4).
d. Primarily reflects the acquisition of the remaining 66.7 percent equity ownership in K-Mc I in December 2004 (Note 4).

13. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	Revenues	Operating Income (Loss)	Net Income (Loss)[a]	Net Income (Loss) per Share Basic	Net Income (Loss) per Share Diluted
	(In Thousands, Except Per Share Amounts)				
2006					
1st Quarter	$ 39,745	$ (6,378)[b]	$ (13,485)[c]	$ (0.50)	$ (0.50)
2nd Quarter	53,330	17,828[d]	14,090	0.50	0.32
3rd Quarter	60,415	(13,719)[e]	(18,992)	(0.67)	(0.67)
4th Quarter	56,248	(30,298)[f]	(30,882)[g]	(1.09)	(1.09)
	$ 209,738	$ (32,567)	$ (49,269)		

	Revenues	Operating Income (Loss)	Net Income (Loss) [a]	Net Income (Loss) per Share Basic	Net Income (Loss) per Share Diluted
	(In Thousands, Except Per Share Amounts)				
2005					
1st Quarter	$ 14,667	$ (2,116)[h]	$ (5,744)	$ (0.24)	$ (0.24)
2nd Quarter	33,952	(12,218)[i]	(16,233)	(0.66)	(0.66)
3rd Quarter	44,265	11,251[j]	6,746	0.27	0.21
4th Quarter	37,243	(19,290)[k]	(26,101)[l]	(1.06)	(1.06)
	$ 130,127	$ (22,373)	$ (41,332)		

a. Reflects net income (loss) attributable to common stock, which includes preferred dividends and amortization of convertible preferred stock issuance costs as a reduction to net income (loss).
b. Includes nonproductive exploratory well drilling and related costs of $12.3 million and $9.7 million of stock-based compensation costs following adoption of SFAS 123R effective January 1, 2006 (Note 1). The amount of the first quarter 2006 charge was higher than the other interim 2006 periods because it, included charges for immediately vesting stock options and options granted to retiree eligible employees.
c. Includes $4.3 million charge related to McMoRan's debt conversion transactions (Note 5).
d. Includes $1.7 million of insurance recovery associated with claims resulting from Hurricanes Ivan and Katrina.
e. Includes $18.5 million of nonproductive exploratory well drilling and related costs.
f. Includes $33.9 million of impairment charges, $12.7 million of nonproductive exploratory well drilling and related costs and an $11.0 million of net exploration expense reimbursements associated with exploration agreements (Note 2).
g. Includes $3.2 million reduction in contractual liability covering certain retired former sulphur employees (Note 11).
h. Includes $5.0 million insurance recovery associated with McMoRan's business interruption claims at Main Pass (Note 4).
i. Includes nonproductive exploratory well drilling and related costs of $18.5 million and an additional insurance recovery of $3.9 million associated with McMoRan's Main Pass business interruption claims (Note 4).
j. Includes estimated damage repair costs totaling $2.8 million associated with Hurricanes Katrina and Rita.
k. Includes nonproductive exploratory well drilling and related costs of $18.0 million and a $12.8 million net charge to expense for settlement of class action litigation (Note 11).
l. Includes $6.5 million charge to expense for modification of previously estimated reclamation costs for remaining facilities at Port Sulphur as a result of hurricane damages (Note 7). Also includes a $3.5 million reduction in a contractual obligation relating to certain former sulphur employees (Note 11).

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

Not Applicable

Item 9A. Controls and Procedures

(a) Evaluation of disclosure controls and procedures. Our chief executive officer and chief financial officer, with the participation of management, have evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-14(c) and 15d-14(c) under the Securities Exchange Act of 1934) as of the end of the period covered by 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 has been no change in our internal control over financial reporting that occurred during the fourth fiscal quarter that has materially affected, or is reasonably likely to materially affect our internal control over financial reporting.

Item 9B. Other Information

Not Applicable

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information set forth under the caption "Information About Director Nominees" and Section 16(a) Beneficial Ownership Reporting Compliance" of the Proxy Statement submitted to the stockholders of the registrant in connection with its 2007 Annual Meeting to be held on April 26, 2007 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 2007 Annual Meeting to be held on April 26, 2007 is incorporated by reference.

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

The information set forth under the captions "Stock Ownership of Certain Beneficial Owners" and "Stock Ownership of Directors and Executive Officers" of the Proxy Statement submitted to the stockholders of the registrant in connection with its 2007 Annual Meeting to be held on April 26, 2007 s incorporated by reference.

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

The information set forth under the captions "Certain Transactions" of the Proxy Statement submitted to the stockholders of the registrant in connection with its 2007 Annual Meeting to be held on April 26, 2007 is incorporated by reference.

Item 14. Principal Accounting Fees and Services

The information set forth under the caption "Independent Auditors" of the definitive Proxy submitted to the stockholders of the registrant in connection with its 2007 Annual meeting to be held on, April 26, 2007 is incorporated by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules

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

(a)(2). Financial Statement Schedules. All financial statement schedules are either not required under the related instructions or are not applicable because the information has been included elsewhere herein.

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

SIGNATURES

Pursuant to the requirements of Section 13 of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on March 15, 2007.

McMoRan Exploration Co.

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

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and the capacities indicated, on March 15, 2007.

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

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

McMoRan Exploration Co.
Exhibit Index

Exhibit Number	
2.1	Agreement and Plan of Merger dated as of August 1, 1998. (Incorporated by reference to Annex A to McMoRan's Registration Statement on Form S-4 (Registration No. 333-61171) filed with the SEC on October 6, 1998 (the McMoRan S-4)).
3.1	Amended and Restated Certificate of Incorporation of McMoRan. (Incorporated by reference to Exhibit 3.1 to McMoRan's 1998 Annual Report on Form 10-K (the McMoRan 1998 Form 10-K)).
3.2	Certificate of Amendment to the Amended and Restated Certificate of Incorporation of McMoRan. (Incorporated by reference to Exhibit 3.2 of McMoRan's First-Quarter 2003 Form 10-Q).
3.3	Amended and Restated By-Laws of McMoRan as amended effective January 30, 2006. (Incorporated by reference to Exhibit 3.3 to McMoRan's Current Report on Form 8-K dated January 30, 2006 (filed February 3, 2006)).
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 dated December 16, 2002. (Incorporated by reference to Exhibit 4.7 to McMoRan's 2002 Form 10-K).
4.8	Warrant to Purchase Shares of Common Stock of McMoRan dated September 30, 2003. (Incorporated by reference to Exhibit 4.8 to McMoRan's 2003 Form 10-K).
4.9	Registration Rights Agreement dated December 16, 2002 between McMoRan and K1 USA Energy Production Corporation. (Incorporated by reference to Exhibit 4.8 to McMoRan's 2002 Form 10-K).
4.10	Indenture dated as of July 2, 2003 by and between McMoRan and The Bank of New York, as trustee. (Incorporated by reference to Exhibit 4.9 to McMoRan's Second Quarter 2003 Form 10-Q).

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

4.12 Purchase Agreement dated September 30, 2004, by and among McMoRan Exploration Co., Merrill Lynch & Co., Merrill Lynch, Pierce, Fenner & Smith Incorporated, and J.P. Morgan Securities Inc. (Incorporated by reference to Exhibit 99.2 to McMoRan's Current Report on Form 8-K dated October 6, 2004 (filed October 7, 2004).

4.13 Indenture dated October 6, 2004 by and among McMoRan and the Bank of New York, as trustee. (Incorporated by reference to Exhibit 99.3 to McMoRan's Current Report on Form 8-K dated October 6, 2004 (filed October 7, 2004)).

4.14 Collateral Pledge and Security Agreement dated October 6, 2004 by and among McMoRan, as pledgor, The Bank of New York, as trustee and the Bank of New York, as collateral agent. (Incorporated by reference to Exhibit 99.4 to McMoRan's Current Report on Form 8-K dated October 6, 2004 (filed October 7, 2004)).

4.15 Registration Rights Agreement dated October 6, 2004 by and among McMoRan, as issuer and Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities Inc. and Jefferies & Company, Inc. as Initial Purchasers. (Incorporated by reference to Exhibit 99.5 to McMoRan's Current Report on Form 8-K dated October 6, 2004 (filed October 7, 2004)).

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

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

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

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

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

10.6 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).

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

10.8 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.)

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

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

10.11 Master Agreement dated October 22, 2002 by and among Freeport-McMoRan Sulphur LLC, K-Mc Venture LLC, K1 USA Energy Production Corporation and McMoRan (Incorporated by reference to Exhibit 10.18 to McMoRan's 2002 Form 10-K).

10.12 Credit Agreement dated as of April 19, 2006 among McMoRan Oil & Gas LLC as borrower, JP Morgan Chase Bank, N.A., as administrative agent, Toronto-Dominion (Texas) LLC, as syndication agent and the Lenders Party Hereto. (Incorporated by reference to Exhibit 10.1 to McMoRan's Current Report on Form 8-K dated April 19, 2006).

10.13 First Amendment to Credit Agreement effective January 19, 2007 among McMoRan Oil & Gas LLC as borrower, JP Morgan Chase Bank, N.A, as administrative agent, Toronto-Dominion (Texas) LLC, as syndication agent and the Lenders Party Hereto.

10.14 Senior Term Loan Agreement effective as of January 19, 2007 among McMoRan Oil & Gas LLC as borrower, JP Morgan Chase Bank, N.A., as administrative agent, TD Securities (USA) LLC, as syndication agent and the Lenders Party Hereto.

Executive and Director Compensation Plans and Arrangements (Exhibits 10.15 through 10.36).

10.15 McMoRan Adjusted Stock Award Plan, as amended and restated. (Incorporated by reference to Exhibit 10.6 to McMoRan's Current Report on Form 8-K dated May 1, 2006 (May 1, 2006 Form 8-K)).

10.16 McMoRan 1998 Stock Option Plan, as amended and restated. (Incorporated by reference to Exhibit 10.5 to McMoRan's May 1, 2006 Form 8-K).

10.17 McMoRan 1998 Stock Option Plan for Non-Employee Directors. (Incorporated by reference to Exhibit 10.14 to McMoRan's Second Quarter 2005 Form 10-Q).

10.18 McMoRan Form of Notice of Grant of Nonqualified Stock Options and Limited Rights under the 1998 Stock Option Plan. (Incorporated by reference to Exhibit 10.15 to McMoRan's Second Quarter 2005 Form 10-Q).

10.19 McMoRan 2000 Stock Incentive Plan, as amended and restated. (Incorporated by reference to Exhibit 10.4 to McMoRan's May 1, 2006 Form 8-K).

10.20 McMoRan Form of Notice of Grant of Nonqualified Stock Options and Limited Rights under the 2000 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.17 to McMoRan's Second Quarter 2005 Form 10-Q).

10.21 McMoRan 2001 Stock Incentive Plan, as amended and restated. (Incorporated by reference to Exhibit 10.3 to McMoRan's May 1, 2006 Form 8-K).

10.22 McMoRan 2003 Stock Incentive Plan, as amended and restated. (Incorporated by reference to Exhibit 10.2 to McMoRan's May 1, 2006 Form 8-K).

10.23	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).
10.24	McMoRan Form of Notice of Grant of Nonqualified Stock Options and Limited Rights under the 2001 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.21 to McMoRan's Second Quarter 2005 Form 10-Q).
10.25	McMoRan Form of Restricted Stock Unit Agreement Under the 2001 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.22 to McMoRan's Second Quarter 2005 Form 10-Q).
10.26	McMoRan Exploration Co. Executive Services Program (Incorporated by reference to Exhibit 10.8 to McMoRan's May 1, 2006 Form 8-K).
10.27	McMoRan Form of Notice of Grants of Nonqualified Stock Options and Limited Rights under the 2003 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.24 to McMoRan's Second Quarter 2005 Form 10-Q).
10.28	McMoRan Form of Restricted Stock Unit Agreement Under the 2003 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.25 to McMoRan's Second Quarter 2005 Form 10-Q).
10.29	McMoRan 2004 Director Compensation Plan. (Incorporated by reference to Exhibit 10.29 to McMoRan's Second Quarter 2004 Form 10-Q).
10.30	Form of Amendment No. 1 to Notice of Grant of Nonqualified Stock Options under the 2004 Director Compensation Plan. (Incorporated by reference to Exhibit 10.7 to McMoRan's May 1, 2006 Form 8-K).
10.31	Agreement for Consulting Services between Freeport-McMoRan Inc. and B. M. Rankin, Jr. effective as of January 1, 1991)(assigned to FM Services Company 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's 1998 Form 10-K).
10.32	Supplemental Letter Agreement between FM Services Company and B.M. Rankin, Jr. effective as of January 1, 2007.
10.33	McMoRan Director Compensation. (Incorporated by reference to Exhibit 10.27 to McMoRan's 2004 Form 10-K).
10.34	McMoRan Exploration Co. 2005 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.1 to McMoRan's May 1, 2006 Form 8-K).
10.35	Form of Notice of Grant of Nonqualified Stock Options under the 2005 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.2 to McMoRan's Current Report on Form 8-K filed May 6, 2005).
10.36	Form of Restricted Stock Unit Agreement under the 2005 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.3 to McMoRan's Current Report on Form 8-K filed May 6, 2005).
12.1	Computation of Ratio of Earnings to Fixed Charges.

14.1	Ethics and Business Conduct Policy. (Incorporated by reference to Exhibit 14.1 to McMoRan's 2003 Form 10-K).
21.1	List of subsidiaries.
23.1	Consent of Ernst & Young LLP.
23.2	Consent of Ryder Scott Company, L.P.
24.1	Certified Resolution of the Board of Directors of McMoRan authorizing this report to be signed on behalf of any officer or director pursuant to a Power of Attorney.
24.2	Powers of Attorney pursuant to which this report has been signed on behalf of certain officer and directors of McMoRan.
31.1	Certification of Principal Executive Officer pursuant to Rule 13a–14(a)/15d-14(a).
31.2	Certification of Principal Financial Officer pursuant to Rule 13a–14(a)/15d-14(a).
32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. Section 1350.
32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. Section 1350.

BOARD OF DIRECTORS

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

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

Robert A. Day (1), 1994
Chairman of the Board and Chief Executive Officer
Trust Company of the West

Gerald J. Ford (1,3), 1998
Chairman of the Board
First Acceptance Corporation

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

Suzanne T. Mestayer (1), 2007
President
New Orleans Market Regions Bank

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

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

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

ADVISORY DIRECTORS

Dr. Morrison C. Bethea
Staff Physician at Ochsner Foundation
Hospital and Clinic
Clinical Professor of Surgery,
Tulane University Medical Center

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

MANAGEMENT

James R. Moffett
Co-Chairman of the Board

Richard C. Adkerson
Co-Chairman of the Board

Glenn A. Kleinert
President and Chief Executive Officer

OPERATIONS

C. Howard Murrish
Executive Vice President
Exploration

Todd R. Cantrall
Vice President of McMoRan Oil & Gas LLC
Engineering

Wm. David Davas
Vice President of McMoRan Oil & Gas LLC
Land

W. Shawn Davis
Vice President of McMoRan Oil & Gas LLC
Exploration

William R. Richey
Vice President of McMoRan Oil & Gas LLC
Operations

David C. Landry
Vice President of Freeport-McMoRan Energy LLC
General Manager-Main Pass Energy Hub™ Project

ADMINISTRATION AND FINANCE

John G. Amato
General Counsel

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

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

W. Russell King
Senior Vice President
Federal Government Affairs

William L. Collier, III
Vice President
Communications

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

INTERNAL AUDITORS

Deloitte & Touche LLP

SHAREHOLDER INFORMATION

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

Investor Relations Department
1615 Poydras Street
New Orleans, LA 70112
504.582.4000
www.mcmoran.com

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

Mellon Investor Services LLC
480 Washington Boulevard
Jersey City, NJ 07310
888.208.1794
www.melloninvestor.com

A link to our Annual Report on Form 10-K filed with the Securities and Exchange Commission, which includes certifications of our Chief Executive Officer (CEO) and Chief Financial Officer (CFO) and the company's Ethics and Business Conduct Policy, is available on our web site. Additionally, copies will be furnished, without charge, to any stockholder of the company entitled to vote at its annual meeting, upon written request.

McMoRan Exploration Co.

1615 POYDRAS STREET
NEW ORLEANS, LA 70112
504.582.4000
WWW.MCMORAN.COM

END