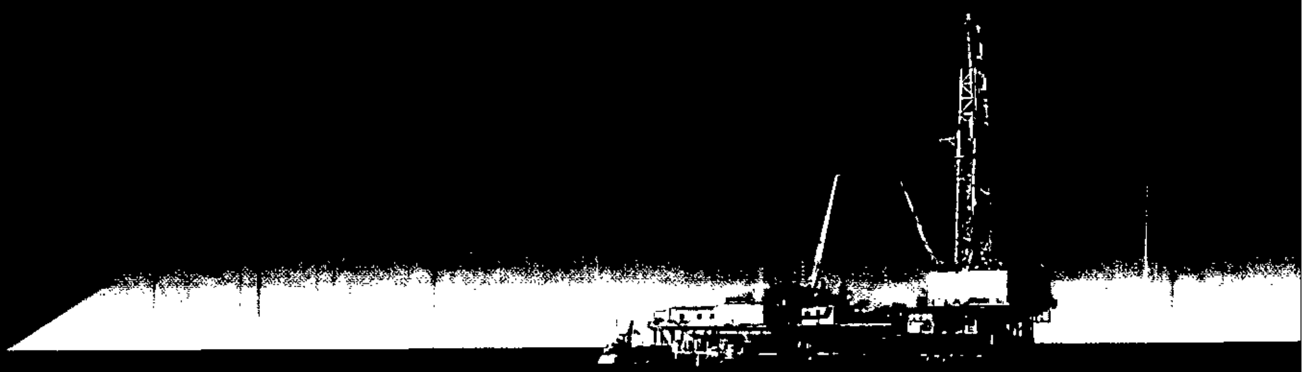
Preparation Meets Opportunity

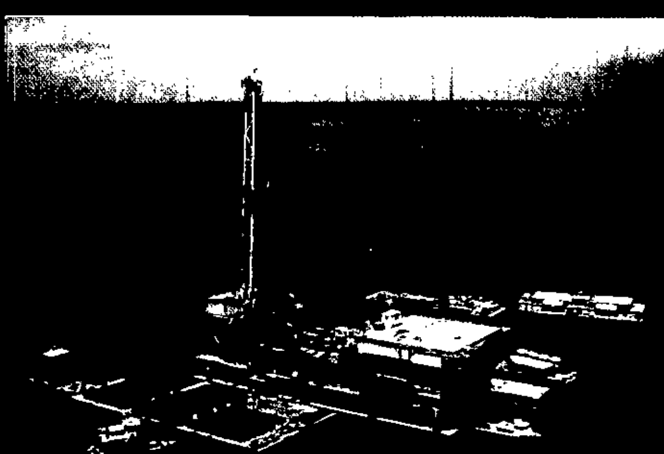
McMoRan Exploration Co. 2007 Annual Report and Form 10-K



McMoRan

Preparation Meets Opportunity

The combination of our $1.1 billion Gulf of Mexico Shelf acquisition and the important discovery at our Flatrock field in South Louisiana positions McMoRan to use our expanded acreage leasehold and "deeper pool" exploration model to grow our asset values.



The barge rig on the cover illustrates the shallow-water nature of McMoRan's exploration drilling opportunities. Close proximity to existing infrastructure in the Gulf Coast region provides the ability to bring discoveries online quickly.

To Our Shareholders:

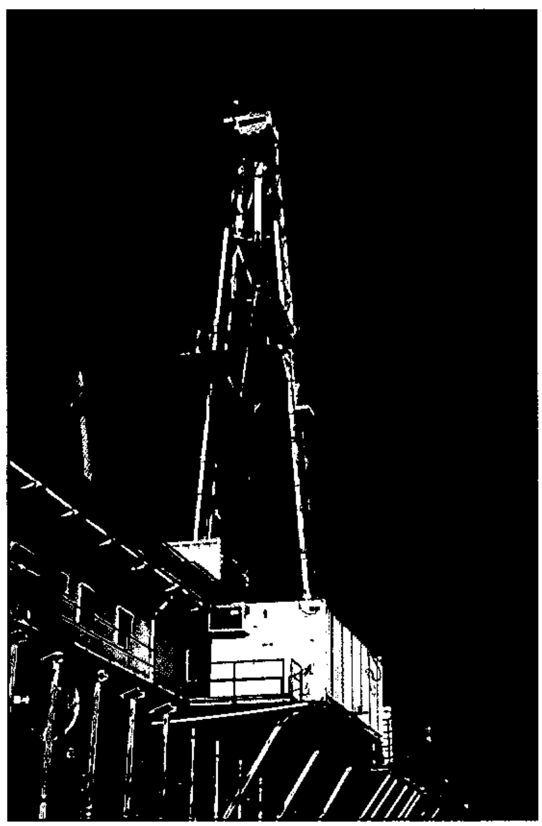
We are pleased to report to you on McMoRan Exploration Co.'s accomplishments during 2007, which include a significant property acquisition, dramatically expanding the scale of our business, and a major new discovery in our active deep gas exploration and development program in the shallow waters of the Gulf of Mexico and onshore South Louisiana.

The combination of our $1.1 billion Gulf of Mexico Shelf acquisition and the important discovery at our Flatrock field in South Louisiana position us to use our expanded acreage position and "deeper pool" exploration model to grow our asset values.

The acquisition of the Newfield Gulf of Mexico properties in August 2007 significantly increased our reserves, production and cash flows and expanded our footprint in our geographic area of focus. The transaction provided us with one of the largest acreage positions on the shelf of the Gulf of Mexico and complements our deep gas exploration program. These properties are generating significant cash flow, providing cash to invest in the future growth of our business and to reduce debt.

During 2007, we made an important discovery at Flatrock, on South Marsh Island Block 212 in 10 feet of water, a clear example of our "deeper pool" concept. The results from three wells drilled to date confirm the potential for significant hydrocarbons. In the third quarter, the discovery well (No. 1, "A" location) encountered eight sands totaling 260 net feet. This well was brought on production in January 2008. Recent production from this well approximated 48 million cubic feet of natural gas per day (MMcf/d) and 845 barrels of condensate per day (12.5 MMcfe/d net to McMoRan).

Following these strong results we permitted additional wells. Delineation drilling at the



No. 2 well ("B" location) in January 2008 indicated improved sand quality a mile to the northwest in the *Rob-L* section. In February 2008, the No. 3 well ("D" location), which is located 3,000 feet south of the discovery, encountered hydrocarbons in the primary *Rob-L* sand seen in the first two wells. The No. 3 well will be deepened to a proposed total depth of 18,800 feet to evaluate additional targets in the *Operc* section.

This large, low relief structure has significant additional development and exploration potential, and has the potential to provide additions to reserves and production. We and our partners plan to pursue these opportunities aggressively. We have rights to 150,000 gross acres in this area and have multiple additional exploration opportunities below 15,000 feet.

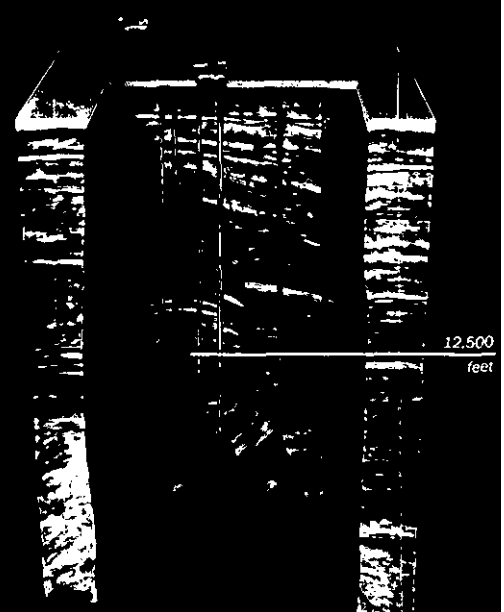
In addition to Flatrock, McMoRan participated in three additional discoveries during 2007, including Laphroaig, onshore St. Mary Parish, Louisiana, Cottonwood Point at Vermilion Block 31 and Hurricane Deep at South Marsh Island Block 217 located approximately 3 miles south of Flatrock. All of these prospects follow our focused "deeper pool" exploration concept. Since 2004, McMoRan has drilled 17 discoveries on 32 prospects.

During 2007, McMoRan's production increased 134 percent, which was primarily the result of production acquired in the Newfield transaction. Our 2007 daily production averaged 152 MMcfe/d, compared to 65 MMcfe/d in 2006.

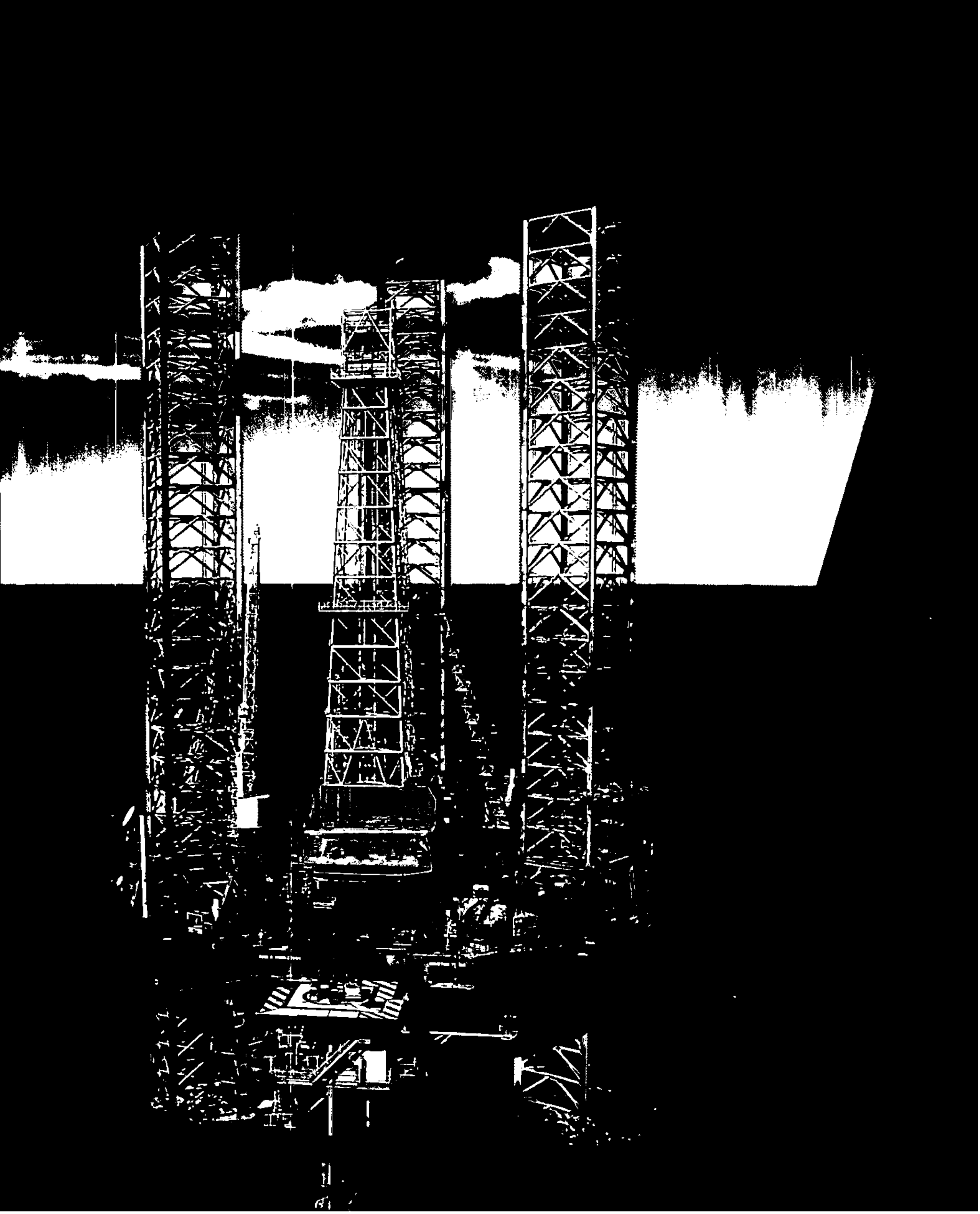
Independent reservoir engineers' estimates of McMoRan's proved oil and gas reserves as of December 31, 2007, including reserves acquired in the Newfield acquisition, were 364 billion cubic feet of natural gas equivalents (Bcfe), compared with 76 Bcfe at December 31, 2006.

In 2008, we will continue to expose shareholders to high risk/ high reward exploration prospects in an effort to add major

Our Flatrock discovery is a clear example of our "deeper pool" concept as it represents the deeper expression of the structural features of the Tiger Shoal Field.



Over 3 trillion cubic feet of natural gas equivalents were produced by others from multiple wells above 12,500 feet in the shallower Tiger Shoal Field.



value to our current base. We will focus on further defining the potential in the Flatrock area and plan to test the high potential Blackbeard ultra-deep exploration well at South Timbalier Block 168 in 70 feet of water. The rights to the Blackbeard project, which was previously drilled to 30,067 feet in August 2006 but temporarily abandoned prior to reaching the primary targets by the previous operator and its partners, were acquired in the Newfield transaction.

In the fourth quarter of 2007, we completed $768 million in equity and debt financings. These offerings enabled us to repay the bridge financing used in connection with the Newfield acquisition, providing us with a long-term capital structure to pursue our exciting opportunities.

The approval of our license application in January 2007 for our Main Pass Energy Hub™ project was a significant development in our efforts to establish an alternative use at the site of our former sulphur operations. We are positive about the commercial potential for the site and are continuing discussions with potential energy suppliers to establish arrangements that would enable us to develop the project to its potential.

The theme of this annual report — "Preparation Meets Opportunity" — describes the McMoRan story. We believe that, "Luck is when preparation meets opportunity." In our case, the knowledge, experience and hard work of our employees, including those hired following the Newfield acquisition, and wisdom and guidance from our Board have prepared us for the opportunities we have to build values for shareholders.

Warmest Regards,

James R. Moffett
Co-Chairman of the Board

Richard C. Adkerson
Co-Chairman of the Board

Glenn A. Kleinert
President and CEO

March 17, 2008

Deep Gas Exploration

As production from shallower hydrocarbon-producing fields on the Gulf of Mexico shelf began to decline, many oil and gas companies shifted their focus to targets in the deep water and foreign locations. However, McMoRan Exploration Co. was convinced that significant energy resources were present in the Deep Miocene geological trend beneath historical or existing production in shallow waters of the Gulf or onshore Louisiana. McMoRan assembled exploration rights to 1.5 million gross acres to pursue these opportunities.

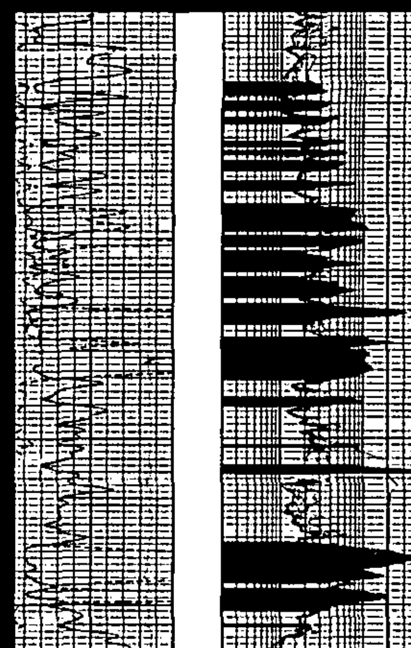
McMoRan's strategy focuses on the "deep gas play," drilling to depths of 15,000 to 25,000 feet to locate older and deeper sediments containing pools of hydrocarbons in the Deep Miocene. It is a largely unexplored area — only about 6% of the wells drilled on the Gulf of Mexico shelf have exceeded 15,000 feet in depth.

In part, other companies were dissuaded by the difficulties of pursuing deeper targets on the shelf. Modern "bright spot" seismic technology, which had been so successful at shallower depths, does not perform the same way in the deeper, older and denser rock of the Deep Miocene. McMoRan's team of geologists and geophysicists, led by Board Co-Chairman James R. Moffett, are uniquely suited for the challenge, many of them having worked this area for four decades. They are richly experienced in the "old-style geology" needed to identify targets in the Deep Miocene — mapping the geometric shape of buried geological structures, predicting sand trends from existing wells, and interpreting all available information to assess trends using modern seismic to enhance the interpretation.

The McMoRan team has encountered success in pursuing this trend, participating in 17 discoveries on 32 prospects that have been drilled and evaluated since 2004, including four announced discoveries in 2007.

McMoRan's most exciting discovery — and one of the most significant discoveries on the Gulf of Mexico shelf in recent history — was announced the third quarter of 2007. The Flatrock No. 1 well, drilled to a total depth of 18,400 feet, encountered eight zones totaling 260 net feet of hydrocarbon bearing sands over a 637-foot gross interval. McMoRan followed up with Flatrock No. 2 one mile northwest, which has encountered eight zones of hydrocarbon bearing sands.

McMoRan's "deeper pool" exploration concept involves drilling below 15,000 feet in the shallow waters on the Shelf of the Gulf of Mexico and onshore South Louisiana.



The logs above depict the presence of sand (yellow indicator on left) and high resistivity (red indicator on right). The combination of sand, high resistivity and porosity indicates hydrocarbon accumulations in a successful well.

We are positive about the commercial potential of the Main Pass Energy Hub™ and are working to establish arrangements that would provide long-term value to shareholders.

Remaining platforms at the site of our former sulphur mine at Main Pass Block 299.

The No. 1 well is producing at strong rates and first production from the No. 2 well is expected by mid-year 2008. The Flatrock No. 3 well, drilled about 3,000 feet south of Flatrock No. 1, has also encountered hydrocarbon-bearing sand zones seen in the first two wells. Drilling continues toward a total depth of 18,800 feet.

A significant advantage to exploring beneath shallower produced fields is existing infrastructure, which allows discoveries to be brought online quickly. The Flatrock No. 1 well began production in January 2008, just a few months following the discovery, and is currently producing at a rate of 48 million cubic feet per day of natural gas and 845 barrels per day of condensate, 12.5 MMcfe/d net to McMoRan.

McMoRan controls approximately 150,000 gross acres in the area of the three Flatrock discoveries — Tiger Shoal and Mound Point, part of OCS 310/Louisiana State Lease 340. McMoRan has made several other discoveries in this area, including Hurricane, Hurricane Deep, JB Mountain and Mound Point and will continue to aggressively pursue its most promising prospects.

Now McMoRan is preparing to embark on its first "ultra-deep" prospect, developing plans to reenter and deepen the Blackbeard No. 1 ultra-deep exploratory well located at South Timbalier Block 168 in 70 feet of water to test the primary targets. The rights to this project, which was previously drilled to 30,067 feet in August 2006 but temporarily abandoned prior to reaching the primary targets, were acquired from Newfield in 2007.

Main Pass Energy Hub™ (MPEH™)

McMoRan is continuing discussions with potential energy suppliers to develop commercial arrangements for the facilities. The project's location near large and liquid U.S. gas markets and the significant potential of the onsite cavern storage provide attractive commercial opportunities for LNG suppliers, natural gas consumers and marketers. The MPEH™ facility, as approved by the U.S. Maritime Administration in 2007, is expected to be capable of storing 28 Bcf of gas in underground storage caverns, producing natural gas liquids and regasifying LNG at a peak rate of 1.6 Bcf per day.

McMoRan Exploration Co.

2007 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, 2007

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

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

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

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.01 per share	New York Stock Exchange
6.75% Mandatory Convertible Preferred Stock	New York Stock Exchange
Preferred Stock Purchase Rights	New York Stock Exchange

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

Indicate by check mark 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, a non-accelerated filer, or a smaller reporting company. See definitions of "accelerated filer," "large accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act (Check one):
☐ Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer (Do not check if a smaller reporting company) ☐ Smaller reporting company

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

The aggregate market value of classes of common stock held by non-affiliates of the registrant was approximately $706 million on February 29, 2008, and approximately $322 million on June 30, 2007.

On February 29, 2008, there were issued and outstanding 54,381,818 shares of the registrant's Common Stock and on June 30, 2007, there were issued and outstanding 34,692,490 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of our Proxy Statement for our 2008 Annual Meeting to be held on June 5, 2008 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, 2007

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PART I

Items 1. and 2. Business and Properties

Except as otherwise described herein or the context otherwise requires, all references to "McMoRan," "MMR," "we," "us," and "our" in this Form 10-K refer to McMoRan Exploration Co. and all entities owned or controlled by McMoRan Exploration Co.

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. We have also provided a glossary of definitions for some of the oil and gas industry terms we use in this Form 10-K beginning on page 100.

BUSINESS

General. 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 area. We have one of the largest acreage positions in the shallow waters of the Gulf of Mexico and Gulf Coast areas, our regions of focus. Our focused strategy enables us to efficiently use our strong base of geologic, engineering, and production experience in these regions in which we have operated for more than 35 years. We also believe that our scale of operations in the Gulf of Mexico provides synergies and a strong platform from which to pursue our business strategy. Our oil and gas operations are conducted through McMoRan Oil & Gas LLC (MOXY), our principal operating subsidiary. In addition to our oil and gas operations, we are pursuing the development of the Main Pass Energy Hub™ (MPEH™) project for the development of a liquefied natural gas (LNG) regasification and storage facility through our wholly owned subsidiary, Freeport-McMoRan Energy LLC (Freeport Energy) (see "— Main Pass Energy Hub™ Project" below).

We conduct substantially all of our operations in the shallow waters of the Gulf of Mexico, commonly referred to as the "shelf," and onshore in the Gulf Coast region. We believe that we have significant exploration opportunities in large, deep geologic structures located beneath the shallow waters of the Gulf of Mexico shelf and often lying beneath shallow reservoirs where significant reserves have already been produced, commonly referred to as "deep gas" or the "deep shelf" (prospects with drilling depths between 15,000 feet to 25,000 feet). In 2007, we acquired substantially all of the proved property interests and related assets of Newfield Exploration Company (Newfield) located on the outer continental shelf of the Gulf of Mexico, which significantly enhanced our portfolio of shelf opportunities by increasing our gross acreage position from approximately 0.3 million acres to approximately 1.5 million acres as of December 31, 2007. The acquisition also increased our deep gas exploration potential, provided access to new "ultra deep" exploration opportunities (prospects with total drilling depths in excess of 25,000 feet) and established us as one of the largest producers on the "traditional shelf" (prospects located at drilling depths not exceeding 15,000 feet) of the Gulf of Mexico (see "—Newfield Property Acquisition" below). Additionally, the proximity of our shelf prospects to an already existing oil and gas infrastructure generally lowers development costs and the time needed to bring production on-line.

We have significant expertise in various exploration and production technologies, including incorporating 3-D seismic interpretation capabilities with traditional structural geological techniques, offshore drilling to significant total depths and horizontal drilling. We employ 65 oil and gas technical professionals, including geophysicists, geologists, petroleum engineers, production and reservoir engineers and technical professionals who have extensive experience in their fields. We also own or have rights to an extensive seismic database, including 3-D seismic data on substantially all of our acreage. We leverage our extensive in-house expertise and advanced technologies to benefit our operations and identify high potential, high risk drilling prospects in the Gulf of Mexico, which is our primary area of expertise. We continue to focus on enhancing reserve and production growth in the Gulf of Mexico by emphasizing and applying these technologies.

Our experience and recognition in the industry as a leader in drilling deep gas wells in the Gulf of Mexico also provides us with opportunities to partner with other established oil and gas companies.

These partnerships typically involve the exploration of our identified prospects or prospects that are brought to us by third parties and allow us to diversify our risks and better manage costs.

Business Strategy. We expect to continue to pursue growth in reserves and production through the exploration, exploitation and development of our existing prospects and new potential prospects. Exploration will continue to be the focus in efforts to maximize value. Our acquisition of the Newfield properties and other recent discoveries has also afforded us with the opportunity to generate value through additional exploration, development and exploitation activities. For 2008, we have allocated approximately 40 percent of our planned capital expenditures for development activities, and we expect to continue to allocate a significant portion of our total capital expenditures to future development activities.

Our exploration strategy, which we refer to as the "deeper pool concept," involves exploring prospects that lie beneath shallower intervals on the Deep Miocene geologic trend where there has been significant past production. Exploration drilling on these deep prospects involves significant costs and risk. A significant advantage to our "deeper pool" exploration strategy is that the infrastructure is in most cases already available, meaning discoveries generally can be brought on line quickly and at generally lower development costs. We believe our ability to identify structures below 15,000 feet by using structural geology augmented by 3-D seismic data will enable us to identify and exploit additional "deeper pool" prospects.

We use our expertise and a rigorous analytical process in conducting our exploration and development activities. While implementing our drilling plans, we focus on:

- allocating investment capital based on the potential risk and reward for each exploratory and developmental opportunity;

- increasing the efficiency of our production practices;

- attracting professionals with geophysical and geological expertise;

- employing advanced seismic applications; and

- using new technology applications in drilling and completion practices.

We intend to continue to strengthen our financial profile and maximize the cash flow from our assets through increased production and aggressive cost management.

The acquired Newfield properties provide us with assets capable of generating significant cash flow, which we plan to use to reduce our current indebtedness and invest in our future growth. Since future oil and gas prices are a significant factor in determining the extent of our potential cash flow, in connection with the acquisition, we entered into derivative contracts for a portion of the anticipated production for 2008, 2009 and 2010. As of December 31, 2007, our hedged position represents approximately 12 percent of our estimated proved reserves, with approximately 9 percent hedged under swap contracts and 3 percent under put contracts (Note 7). We may review future opportunities to hedge an additional portion of our production.

During 2007, we made one of our most significant deep gas discoveries in recent history at the Flatrock discovery at South Marsh Island Block 212. To date, we have drilled three successful wells in this field and plan to pursue further exploration and development in this high-potential area.

Newfield Property Acquisition. As discussed in "Management's Discussion and Analysis of Financial Condition and Results of Operation and Quantitative and Qualitative Disclosures About Market Risk — Operational Activities" included in Items 7. and 7A. in this Form 10-K, on August 6, 2007, we completed the acquisition of substantially all of the proved property interests and related assets of Newfield located on the outer continental shelf of the Gulf of Mexico for total cash consideration of approximately $1.1 billion and the assumption of the related reclamation obligations. The effective date of the acquisition was July 1, 2007.

Our acquisition of the Newfield properties provides us with substantial reserves, production and exploration rights on the shelf of the Gulf of Mexico. At the time of the transaction, the acquired Newfield properties included 124 fields on 148 offshore blocks covering approximately 1.25 million gross acres (approximately 0.5 million acres net to our interests). Estimated proved reserves for the acquired Newfield properties as of July 1, 2007 totaled approximately 321 Bcfe, of which 71 percent represented proved natural gas reserves. The acquired Newfield properties produced an average of approximately 235 MMcfe/d for the quarter ended December 31, 2007.

We also acquired 50 percent of Newfield's interest in certain unproved exploration leases on the outer continental shelf of the Gulf of Mexico. At December 31, 2007, these interests encompassed 13 primary term blocks covering approximately 64,000 gross acres. In addition, we acquired a majority interest of Newfield's ownership in leases associated with its Treasure Island and Treasure Bay ultra deep prospects.

The acquired Newfield properties significantly expand our production and cash flow generating capacity and provide us with expanded deep gas opportunities on the shelf of the Gulf of Mexico. The benefits of the acquisition include:

- substantial reserves, production and leasehold interests of approximately 1.25 million gross acres in an area on the outer continental shelf of the Gulf of Mexico, where we have significant experience and expertise;
- strong cash flows, which will enable us to reduce our debt rapidly and invest in high potential, high risk projects; and
- increased scale of operations, technical depth and expanded financial resources providing a strong platform from which we will be able to pursue growth opportunities in our core area of operations.

Main Pass Energy Hub™ Project. We are pursuing the development of a multifaceted energy facility at MPEH™, including the potential development of a facility to receive and process LNG and store and distribute natural gas. We have completed preliminary engineering for the development of the MPEH™ project located at our Main Pass facilities located offshore in the Gulf of Mexico, 38 miles east of Venice, Louisiana. We are continuing discussions with potential energy suppliers to develop commercial arrangements for the facilities.

Following an extensive review, in January 2007 the Maritime Administration (MARAD) approved our license application for the MPEH™ project. MARAD concluded in its Record of Decision that construction and operation of the MPEH™ deepwater port would 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™ would fill a vital role in meeting national energy requirements going forward and the port's offshore deepwater location would 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.

The project's proximity to large and liquid U.S. gas markets and the significant potential of the onsite cavern storage provide attractive commercial opportunities for energy suppliers and natural gas consumers and marketers. The MPEH™ facility is approved with a capacity 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 of natural gas to the U.S. market, including gas from storage.

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.
  * Our dedicated pipeline system would deliver to eight major interstate pipelines; and
  * Onsite gas conditioning would 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.

Prior to commencing construction of the facilities, we expect to enter into commercial arrangements that would enable us to finance the construction costs, projected to be approximately $800 million, with a potential additional investment of up to $600 million for pipelines and cavern storage based on preliminary engineering estimates completed in the second half of 2006. The total project investment will ultimately depend on comprehensive engineering studies, future estimated construction cost levels and project specification requirements for supply.

We currently own 100 percent of the MPEH™ project. However, two entities have separate options to participate as passive equity investors for up to an aggregate of 25 percent of our equity interest in the project. Future financing arrangements may also reduce our equity interest in the project. For additional information regarding the risks associated with the MPEH™ project, our estimated future reclamation costs and risks related to our reclamation obligations associated with the former assets and operations of the Main Pass facilities, see "Risk Factors" included in Item 1A. of this Form 10-K.

Marketing. We currently sell our natural gas in the spot market at prevailing prices. Prices on the spot market fluctuate with demand and as a result of related industry variables. We generally sell our crude oil and condensate one month at a time at prevailing market prices. From time to time, we may enter into transactions that fix the future prices for a portion of oil and natural gas sales volumes, through the issuance of oil and gas derivative contracts. See Note 7 for information regarding our existing oil and natural gas derivative contracts.

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 affects profitability. For additional information related to the risks associated with the regulation of our oil and gas activities, see "Risk Factors" included in Item 1A. of this Form 10-K.

Exploration, Production and Development. Our exploration, production and development operations are subject to regulation at both the federal and state levels. Among other things, operators are required 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. As of December 31, 2007, after giving effect to the acquired Newfield properties, we currently have interests in 291 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 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 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 Louisiana and Texas. 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 penalties for any pollution resulting from our operations. We believe that our operations substantially comply with applicable environmental laws. For additional information related to risks associated with these environmental laws and their impact on our operations, see "Risk Factors" included in Item 1A. of this Form 10-K.

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, or 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, 2007, we had a total of 110 employees located at our New Orleans, Louisiana headquarters and the Houston, Texas and Lafayette, Louisiana offices that were established in connection with the Newfield transaction. These employees are primarily devoted to production, regulatory, engineering, land, geological and various administrative functions. Our employees are not represented by any union or covered by a collective bargaining agreement, and we believe our relations with our employees are satisfactory.

Additionally, 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. Either party may terminate the services agreement at any time upon 90 days notice (Note 12).

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 are intended to minimize our development and operating costs as well as allow our management staff to focus on directing our oil and gas operations.

We maintain an ethics and business conduct policy applicable to all personnel employed by or affiliated with us. Our corporate governance guidelines and our ethics and business conduct policy are available at www.mcmoran.com and are available in print upon request. We intend to post promptly on our website amendments to or waivers, if any, of our ethics and business conduct policy made with respect to any of our directors and executive officers.

PROPERTIES

Oil and Gas Reserves. Our estimated proved oil and natural gas reserves at December 31, 2007 totaled 363.9 Bcfe, of which 67.5 percent represented natural gas reserves. All of our proved reserve estimates were prepared by Ryder Scott Company, L.P., an independent petroleum engineering firm, in accordance with the rules and regulations required by the SEC.

Our estimated proved reserves as of December 31, 2007 are summarized in the table below:

	Gas (MMcf)	Oil and condensate (MBbls)	Total (MMcfe)
Proved developed:			
Producing	91,710	8,049	140,006
Non-producing	98,340	9,122	153,069
Shut-in	13,545	281	15,233
Total proved developed	203,595	17,452	308,308
Proved undeveloped	42,011	2,265	55,600
Total proved reserves	245,606	19,717	363,908

The following table presents the present value of estimated future net cash flows before income taxes from the production and sale of our estimated proved reserves as of December 31, 2007 (in thousands).

	Proved Reserves		
	Developed	Undeveloped	Total
Estimated undiscounted future net cash flows before income taxes	$ 2,021,404	$ 306,687	$ 2,328,091
Present value of estimated future net cash flows before income taxes [a]	$ 1,589,089	$ 229,486	$ 1,818,575

a. Calculated based on the prices and costs prevailing at December 31, 2007 and using a 10 percent per annum discount rate as required by the SEC. The weighted average price for all our properties with proved reserves was $92.69 per barrel of oil and $7.22 per Mcf of natural gas at December 31, 2007.

Production, Unit Prices and Costs. Our production during 2007 totaled approximately 39.0 Bcf of natural gas and 2.7 MMBbls of crude oil and condensate or an aggregate of 55.5 Bcfe. Our production during 2006 totaled approximately 14.5 Bcf of natural gas and 1.6 MMBbls of crude oil and condensate or an aggregate of 23.9 Bcfe. Average daily production from our properties, net to our interests, approximated 152 MMcfe/d in 2007, 65 MMcfe/d in 2006 and 36 MMcfe/d in 2005.

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,		
	2007	2006	2005
Net natural gas production (Mcf)	38,994,000	14,545,600	7,938,000
Net crude oil and condensate production, excluding Main Pass (Bbls)[a]	2,180,800	779,000	387,100
Net crude oil production from Main Pass (Bbls)	564,000	775,500	463,000
Sales prices:			
Natural gas (per Mcf)	$ 7.01	$ 7.05	$ 9.24
Crude oil and condensate, including Main Pass (per Bbl)[b]	76.55	60.55	53.82
Production (lifting) costs: [c]			
Per barrel for Main Pass [d]	$44.17	$35.76	$41.46
Per Mcfe for other properties [e]	1.88	1.34	1.06

a. The volume produced during 2007 includes approximately 358,900 equivalent barrels of oil and condensate associated with $19.3 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 178,700 and 106,700 equivalent barrels of oil ($9.6 million and $5.0 million of revenues) associated with plant products during 2006 and 2005, respectively.
b. Realization does not include the effect of the plant product revenues discussed in (a) above.
c. 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 including well insurance costs.
d. Production costs for Main Pass included approximately $1.8 million, $3.17 per barrel in 2007, $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.
e. Production costs were converted to an Mcf equivalent on the basis of one barrel of oil being equivalent to six Mcf of natural gas. Production costs included workover expenses totaling $19.7 million or $0.38 per Mcfe in 2007, $4.5 million or $0.23 per Mcfe in 2006 and $1.2 million or $0.13 per Mcfe in 2005.

Acreage. As of December 31, 2007, we owned or controlled interests in 603 oil and gas leases in the Gulf of Mexico and onshore Louisiana and Texas covering 1.52 million gross acres (0.64 million acres net to our interests). Our acreage position on the outer continental shelf includes 1.30 million gross acres (0.57 million acres net to our interests). We own leasehold interests to approximately 0.5 million gross acres, 0.1 million net to our interests, that are scheduled to expire in 2008. We also hold potential reversionary interests in oil and gas leases that we have farmed-out or sold to other oil and gas exploration companies. Interest in these leases will partially revert to us upon the achievement of specified production thresholds or the realization of specified net production proceeds.

The following table shows the oil and gas acreage in which we held interests as of December 31, 2007. The table does not account for our gross acres associated with our farm-in, or certain other farm-out arrangements (approximately 0.10 million gross acres). For more information regarding our acreage position, see Note 3.

	Developed		Undeveloped	
	Gross Acres	Net Acres	Gross Acres	Net Acres
Offshore (federal waters)	709,391	412,034	593,435	162,641
Onshore Louisiana and Texas	36,769	18,255	71,898	30,523
Total at December 31, 2007	746,160	430,289	665,333	193,164

Oil and Gas Properties. Our properties are primarily located on the outer continental shelf in the shallow waters of the Gulf of Mexico. We classify our activities based upon the drilling depth of our prospects. Our three principal classifications for Gulf of Mexico shelf prospects are traditional shelf, deep shelf and ultra deep shelf. Prospects located at drilling depths not exceeding 15,000 feet are considered to be traditional shelf prospects. Prospects exceeding 15,000 feet but not exceeding 25,000 feet are considered deep shelf prospects. Any prospect located at drilling depths exceeding 25,000 feet is considered to be an ultra deep shelf prospect. Since 2004, we have focused our exploration activities almost exclusively on deep shelf prospects, generally those located beneath shallow reservoirs where significant reserves have already been produced. Our acquisition of the Newfield properties significantly enhances our portfolio of shelf opportunities, increases our deep shelf exploration potential and provides access to new ultra deep shelf opportunities.

In addition to our Gulf of Mexico shelf properties, we also have property interests onshore and in the state waters of Louisiana and Texas and three deepwater properties in the Gulf of Mexico. The deepwater properties involve prospects located in water depths exceeding 1,000 feet.

Deep Shelf. The following table identifies select deep shelf discoveries as of December 31, 2007.

	Working Interest (%)	Net Revenue Interest (%)	Water Depth (feet)	Total Depth (feet)	Production [a] (MMcfe/d)	
					Gross	Net
Louisiana State Lease 18090 "Long Point" [b]	37.5	26.7	8	19,000	54	14
St. Mary Parish, LA "Laphroaig" [c]	50.0	38.5	<10	19,060	43	16
Louisiana State Lease 18350 "Point Chevreuil"	25.0	17.5	<10	17,051	13	2
Onshore Vermilion Parish, LA "Liberty Canal" [c]	37.5	27.6	n/a [d]	16,594	12	3
South Marsh Island Block 217 "Hurricane" [b]	27.5	19.4	10	19,664	11	3
Vermilion Blocks 16/17 "King Kong" [c]	40.0	29.2	13	18,918	3	1
South Marsh Island Block 212 "Flatrock" [b, e]	25.0	18.8	10	18,400	[f]	[f]
South Marsh Island Block 217 "Hurricane Deep" [b, e]	25.0	20.8	<10	21,500	[g]	[g]

a. Reflects average daily production rates for the fourth quarter of 2007.
b. We were operator for drilling exploratory wells at these prospects. We relinquished being operator following successful completion of the related wells.
c. Wells operated by us.
d. Prospect is located onshore in Vermilion Parish, Louisiana.
e. Prospect will be eligible for deep gas royalty relief under current MMS guidelines, which could result in an increased net revenue interest for early production. 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 2007, 2006 or 2005.
f. The well commenced production on January 28, 2008 and on March 14, 2007 is producing at a gross rate of approximately 53 MMcfe/d and approximately 12 Mmcfe/d net to us.
g. The well commenced production on January 24, 2008 and on March 14, 2007 is currently producing at a rate of approximately 22 MMcfe/d and approximately 5 MMcfe/d net to us.

Traditional Shelf. The following table identifies select producing traditional shelf properties as of December 31, 2007.

Lease	Working Interest	Net Revenue Interest	Water Depth	Production [a]	
				Gross	Net
	(%)	(%)	(feet)	(MMcfe/d)	
Eugene Island Block 182 [b,c]	66.9	52.8-63.6	88	22	13
Eugene Island Blocks 251/262 [b]	56.9	43.9	160	23	10
Main Pass Block 299 [b]	100.0	83.3	210	11	9
South Marsh Island Block 49 [b]	100.0	83.3	98	10	8
High Island Block 474 [c]	69.2	57.8	180	14	8
Grand Isle Block 3 [b]	50.0	36.5	10	20	7
South Timbalier Block 148 [b]	58.2	40.0	86	17	7
East Cameron Block 373	40.0	33.3	348	19	6
South Marsh Island Block 141 [b]	87.3	66.0	230	10	6
West Delta Block 133 [b]	75.0	54.3	373	11	6
Vermilion Block 215 [b]	92.0	76.8	115	8	6

a. Based on average daily production rates for fourth quarter of 2007.
b. Fields operated by us.
c. This property has multiple wells with varying ownership interests. Interests reflected in this table are approximate average working interest and net revenue interest for the field.

Ultra Deep Shelf. We currently have no production from our ultra-deep shelf properties. We acquired interests from Newfield in leases associated with its Treasure Island and Treasure Bay ultra-deep gas prospect inventory. This ultra-deep prospect inventory currently consists of 86 lease blocks. We have been designated operator of the Blackbeard prospect, which is located at South Timbalier Block 168 in 70 feet of water (see "Oil and Gas Activities—Discoveries and Development Activities—Blackbeard" below). We currently hold an approximate 87.3 percent working interest in the well but are in discussions with third parties to participate in this prospect, the results of which are expected to decrease our current working interest. We are working to identify "deeper pool" exploration prospects on this ultra deep shelf acreage position.

Deep Water and Other Properties. Our deepwater properties are located in the Gulf of Mexico beyond the outer continental shelf. We currently have interests in three properties in the deepwater of the Gulf of Mexico. Our deepwater properties are the Garden Banks Block 625, 208 and 161 fields.

Oil and Gas Activity.

Discoveries and Development Activities. Since 2004, we have participated in 17 discoveries on 32 prospects that have been drilled and evaluated, including four discoveries announced in 2007. Three additional prospects are not yet fully evaluated.

Flatrock. We are pursuing aggressively the opportunities in the Flatrock area, located on OCS 310 at South Marsh Island Block 212 in approximately 10 feet of water.

The Flatrock No. 1 discovery well was drilled to a total depth of 18,400 feet in August 2007. Wireline and log-while-drilling porosity logs confirmed that the well encountered eight zones totaling 260 net feet of hydrocarbon bearing sands over a combined 637 foot gross interval, including five zones in the Rob-L section and three zones in the Operc section. Initial production was established in the 17,200 foot Operc interval on January 28, 2008. At March 14, 2008, the well was producing at a rate of approximately 48 MMcf/d and 845 barrels of condensate per day, approximately 12 MMcfe/d net to us.

The Flatrock No. 2 delineation well, which commenced drilling on October 7, 2007, is located approximately one mile northwest of the Flatrock discovery well. The well was drilled to a total depth of

17,684 feet and log while-drilling tools have indicated an additional resistive zone totaling 30 net feet of pay below 17,100 feet in the Operc Section. In total, the well encountered eight sands including four zones as indicated by wireline logs which contained 190 net feet of hydrocarbon bearing sands over a combined 318 foot gross interval above 15,500 feet in the Rob-L section and four zones as indicated by log-while-drilling tools totaling 70 net feet of resistivity below 15,500 feet in the Rob-L and Operc sections. Completion operations have commenced with initial production expected to be established in the thickest Rob-L interval by mid-year 2008.

The Flatrock No. 3 delineation well commenced drilling on November 5, 2007 and is located approximately 3,000 feet south of the Flatrock discovery well. The well has encountered a Rob-L interval, which contained 70 net feet of hydrocarbon bearing sands over a combined 280 foot gross interval above 15,500 feet as indicated by wireline logs and log-while-drilling tools have indicated two additional zones, a Rob-L sand and an Operc sand, totaling 40 net feet of resistivity. We are currently drilling in the top of the Operc sand. As anticipated, this Operc sand is consistent with and structurally higher to the sand currently producing in the Flatrock No. 1 discovery well. The well will be deepened to a proposed total depth of 18,800 feet to evaluate additional targets in the Operc sections.

Our initial production at the Flatrock No. 1 well and drilling results at the Flatrock No. 2 and 3 wells indicate that the Flatrock discovery is potentially significant. These wells are located in shallow water depths in an area with available infrastructure and the expansion of pipeline and facility capacity is currently underway. Depending on production from Flatrock and the development and production activities in the area, additional infrastructure expenditures may be required.

Hurricane Deep. The Hurricane Deep Prospect, located on South Marsh Island Block 217, commenced drilling on October 26, 2006 and was drilled to 20,712 feet true vertical depth. Logs have indicated that an exceptionally thick upper Gyro sand was encountered totaling 900 gross feet. Based on wireline logs, the top of the Gyro sand indicated 40 feet of net hydrocarbons in a 53 foot gross interval. This sand thickness suggests that prospects in the Mound Point/Hurricane/JB Mountain/Blueberry Hill area may have thick sands as potential Gyro reservoirs. The well commenced production from the Gyro sand on January 24, 2008 and at March 14, 2008 was producing at a gross rate of approximately 22 MMcfe/d, 5 MMcfe/d net to us. The Hurricane Deep well has two zones behind pipe in the shallower Rob-L and Operc sections of the well. We have a 25.0 percent working interest and a 17.7 percent net revenue interest in the Hurricane Deep Prospect which is located in twelve feet of water on OCS 310, one mile northeast of the currently producing Hurricane discovery well. We control 7,700 gross acres in this area.

Tiger Shoal/Mound Point. We control approximately 150,000 gross acres in the Tiger Shoal/Mound Point area (OCS Block 310/Louisiana State Lease 340). The addition of the Flatrock discovery follows a series of prior discoveries we have made in this area, including Hurricane, Hurricane Deep, JB Mountain, and Mound Point. Efforts to identify additional prospects in this area are in progress. We have drilled a total of eight successful wells in the OCS Block 310/Louisiana State Lease 340 area. We have multiple additional exploration opportunities with significant potential on this large acreage position.

Cottonwood Point. The Cottonwood Point well located on Vermilion Block 31 commenced drilling on May 1, 2007 and was drilled to 19,987 feet. Wireline logs have indicated approximately 43 net feet of hydrocarbon bearing sands over an approximate 92 foot gross interval in the upper Rob-L section. The targeted deeper Operc objectives were determined not to contain commercial quantities of hydrocarbons. The well was completed in the Rob-L section and production is expected to commence in the second quarter of 2008 following facilities installation.

Blackbeard. We acquired the Blackbeard prospect as part of our acquisition of the Newfield properties. The Blackbeard West well was previously drilled by Newfield and its partners to a total depth of 30,067 feet and encountered a thin gas-bearing sand below 30,000 feet. The well was temporarily abandoned in August 2006 before reaching its primary targets. We have contracted a rig to re-enter and deepen the well to a proposed depth of approximately 31,200 feet. The Blackbeard West well is located at South Timbalier Block 168 in 70 feet of water. The rig is on location and drilling operations are expected to commence in the near term. We currently hold an approximate 87.3 percent working interest in the well but are in discussions with third parties to participate in this prospect, the results of which are expected to decrease our current working interest.

Exploratory and Development Drilling. 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 periods presented.

	2007		2006		2005	
	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Productive	4	1.150	6	2.375	4	1.426
Dry	1	0.150	4	1.185 [a]	6	2.021 [b]
In-progress	5	1.673	4	1.808	5	1.728
Total	10	2.973	14	5.368	15	5.175
Development						
Productive	-	-	7	2.613	2	0.667
Dry	1	0.250	-	-	-	-
In-progress [c]	2	1.091	2	0.854	5	1.904
Total	3	1.341	9	3.467	7	2.571

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 (increased to 0.541 net interest for 2007) and 0.550 net interest in the JB Mountain No. 3, which have been temporarily abandoned.

Productive Well Interests. The following table shows our interest in productive oil and natural gas wells as of December 31, 2007. 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 (1) 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 (2) 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	175	81.267	87	47.580
Onshore	24	9.078	4	2.251
Total	199	90.345	91	49.831

Exploration Agreements.
Newfield. In connection with our acquisition of the Newfield properties, we also acquired 50 percent of Newfield's interest in certain unproved exploration leases on the outer continental shelf of the Gulf of Mexico. At December 31, 2007, these interests encompassed 13 primary term blocks covering approximately 64,000 gross acres. In addition, we acquired a majority interest of Newfield's ownership in leases associated with the Treasure Island and Treasure Bay ultra deep prospects. We have not drilled any wells on these acquired interests; however, the Blackbeard West ultra deep well is expected to commence in the first quarter of 2008 (see "Oil and Gas Activity – Discoveries and Development Activities – Blackbeard" above). For additional information about the acquisition of the Newfield properties, see "Business—Newfield Property Acquisition" above.

Plains Exploration & Production Company. Prior to our Newfield acquisition, we entered into an exploration agreement with Plains pursuant to which Plains obtained the right to participate in various exploration prospects in limited areas being explored by us. None of the properties we acquired from Newfield are subject to our agreement with Plains. As of December 31, 2007, Plains has participated in six prospects under the terms of this exploration arrangement.

El Paso Farm-Out Arrangement. We have a farm-out agreement with El Paso Production Company (El Paso) which resulted in the JB Mountain and Mound Point Offset discoveries in the OCS 310 and Louisiana State Lease 340 areas, respectively. Through this arrangement, El Paso currently has rights to an approximate 13,000 gross acres surrounding the JB Mountain prospect (55 percent working interest and a 38.8 percent net revenue interest) and the Mound Point Offset prospect (30.4 percent working interest and a 21.6 percent net revenue interest). El Paso retains 100 percent of the program's interests until the aggregate production attributable to the program's net revenue interests reaches 100 Bcfe, after which, ownership of 50 percent of the program's working and net revenue interests would revert to us. There are three producing wells subject to the 100 Bcfe arrangement, which averaged an aggregate gross rate of approximately 26 MMcfe/d during 2007. We do not expect payout under the 100 Bcfe arrangement will occur in 2008.

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, or current facts, that address activities, events, outcomes and other matters that we plan, expect, intend, assume, believe, budget, predict, forecast, project, estimate or anticipate (or other similar expressions) will, should or may occur in the future, such as: statements regarding our financial plans; our indebtedness; acquisitions; 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:

Risks Relating to Financial Matters

Our substantial indebtedness, including the indebtedness incurred in connection with the acquisition of the Newfield properties and our recent senior notes offering, could adversely affect our operating results and financial condition.

We incurred significant debt to fund the acquisition of substantially all of the proved property interests and related assets of Newfield Exploration Company (Newfield) located on the outer continental shelf of the Gulf of Mexico, as well as in connection with the offering of our 11.875% Senior Notes to repay a portion of that debt. As of December 31, 2007, the outstanding principal amount of our indebtedness was approximately $800.5 million, including $100.9 million for our 6% convertible senior notes that will mature on July 2, 2008. Our level of indebtedness could have important consequences. For example, it could:

- make it difficult for us to service our debt;
- increase our vulnerability to adverse changes in economic and industry conditions;
- require us to dedicate a substantial portion of our cash flow from operations and proceeds of equity issuances or asset sales to pay or provide for our indebtedness, thus reducing the

availability of cash flows to fund working capital, capital expenditures, acquisitions, investments and other general corporate purposes;

- limit our flexibility to plan for, or react to, changes in our businesses and the markets in which we operate;
- place us at a competitive disadvantage to our competitors that have less debt; and
- limit our ability to borrow money or sell stock to fund our working capital, capital expenditures, acquisitions, and debt service requirements and other financing needs.

In addition, we may need to incur additional indebtedness in the future in the ordinary course of business. The terms of our amended and restated credit facility and other agreements governing our indebtedness allow us to incur limited amounts of additional debt. If new debt is added to current debt levels, the risks described above could intensify. Further, if future debt financing is not available to us when required or is not available on acceptable terms, we may be unable to grow our business, take advantage of business opportunities, respond to competitive pressures or refinance maturing debt, any of which could have a material adverse effect on our operating results and financial condition.

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 agreements with third parties to support the funding of 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 Production Company, a subsidiary of El Paso Corporation (El Paso), to fund the exploration and development of four of our prospects, two of which resulted in discoveries and two of which were nonproductive. We have also participated in a multi-year exploration venture agreement with a private exploration and production company, which 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. Finally, prior to our Newfield acquisition, we entered into an exploration agreement with Plains pursuant to which Plains obtained the right to participate in various exploration prospects in limited areas being explored by us. None of the properties we acquired from Newfield are subject to our agreement with Plains. As of December 31, 2007, Plains has participated in six prospects under the terms of this exploration arrangement.

We may also seek to enter into additional farm-out or other arrangements with other companies. 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, or specified net production proceeds have been received by our partners in these ventures. Consequently, even if exploration and development of our 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.

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 Main Pass Energy Hub™ (MPEH™) project, incurred losses of $63.6 million in 2007, $44.7 million in 2006 and $31.5 million in 2005. 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 both our oil and gas properties, including the acquired Newfield properties and our former sulphur operations, including Main Pass and Port Sulphur.

As of December 31, 2007, we had accrued $294.7 million relating to the reclamation liabilities with respect to our oil and gas properties, including $268.6 million of estimated reclamation liabilities assumed with the acquisition of the Newfield properties. Among these reclamation obligations are the plugging and abandonment of wells, the reclamation and removal of platforms, facilities and pipelines and the repair and replacement of wells, equipment and facilities, including obligations associated with damages sustained from Hurricanes Ivan, Katrina and Rita. The scope and cost of these obligations may ultimately be materially greater than estimated at the time of the acquisition.

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 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 or other materials at closed mines in coastal areas that have become exposed through coastal erosion. As of December 31, 2007, we had $10.5 million relating to accrued reclamation liabilities with respect to our discontinued Main Pass sulphur operations of which $2.6 million has been prepaid as of December 31, 2007, and $10.8 million relating to accrued reclamation liabilities with respect to our other discontinued sulphur operations, including $9.6 million for the Port Sulphur facilities. We are in the process of completing closure activities at the Port Sulphur facilities 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 necessary resources to satisfy these obligations in the future, or that we will be able to satisfy applicable bonding requirements.

We are subject to indemnification obligations with respect to: (1) the sulphur transportation and terminaling assets that we sold in June 2002, including sulphur and oil and gas obligations arising under environmental laws; and (2) our acquisition of the Newfield properties.

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 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. We have also assumed and agreed to indemnify Newfield from certain potential obligations, including environmental obligations relating to our acquisition of the Newfield properties. The scope and cost of these obligations may ultimately be materially greater than estimated at the time of the acquisition. Our liabilities with respect to those obligations could adversely affect our operations and liquidity.

Our ability to collect our accounts receivable depends on the continuing creditworthiness of our customers.

The majority of our accounts receivable result from oil and natural gas sales or joint interest billings to third parties in the energy industry. Our credit risk associated with these third parties may increase as we produce and sell oil and natural gas on a larger scale. These third parties may be affected by adverse changes in market conditions resulting in downgrades to credit ratings or other consequences. While we sell oil and natural gas to companies that we believe are reasonable credit risks, there is no guaranty that the risk associated with the creditworthiness of these parties will not increase.

Risks Relating to our Operations

Acquisitions involve risks, including unanticipated liabilities and expenses associated with acquired properties, difficulties in integrating acquired properties into our business, diversion of management attention, and increases in the scope and complexity of our operations.

We completed the Newfield acquisition on August 6, 2007 with an effective date of July 1, 2007. We were only able to complete a limited review of the acquired properties by the time of the August 6 closing and we may have not identified all existing or potential contingent exposures to which we could be subject in the future from the acquisition. It is possible that we will discover issues with an acquired property asset or potential liability that we did not anticipate at the time the acquisition was completed. These issues may be material and could include, among other things, unexpected environmental issues, title defects or other liabilities. Often, we acquire properties on an "as is" basis and have limited or no remedies against the seller, including Newfield, with respect to these potential exposures.

The failure to successfully integrate acquired operations into our existing operations may affect our ability to operate at optimal performance levels and may require significant management attention and financial resources that would otherwise be available for the ongoing development or expansion of our existing operations. Challenges involved in the integration process may include retaining key employees, maintaining key employee morale, addressing differences in business cultures, processes and systems and developing internal expertise regarding the acquired properties and assets.

The high-rate production characteristics of our Gulf of Mexico properties and our ownership interests in prospects subject to farm-out arrangements subject us to high reserve replacement needs.

Our future financial performance depends in large part on our ability to find, develop and produce oil and natural gas reserves, and we cannot make any assurances that we will be able to do so profitably. Unless we conduct successful exploration and development activities, acquire properties with proved reserves, or meet certain production and related thresholds in our prospects subject to farm-out arrangements, our proved reserves will decline as they are produced.

Producing natural gas and oil reservoirs are generally characterized by declining production rates that vary depending on reservoir characteristics and other factors. Production from the Gulf of Mexico shelf generally declines at a faster rate than in other producing regions of the world. 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.

Additionally, 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. As a result, significant discoveries on these prospects will be needed before we can increase our revenues or our proved oil and gas reserves. We cannot predict with certainty that 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 increase might occur.

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

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

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

In the near-term, we plan to continue to pursue the drilling of our exploration prospects and the development of other projects, such as the MPEH ™ project. We incurred $153.2 million in capital expenditures in 2007. We expect that our capital expenditures during 2008 will total approximately $225 million, including $40 million of carryover costs from 2007, $90 million for costs associated with Flatrock, Blackbeard West and other exploration opportunities and approximately $95 million for anticipated development costs. These expenditures could increase if our drilling efforts are successful. Although we intend to fund our near-term expenditures with available cash, operating cash flows and borrowings under our senior secured revolving credit facility, we may need to raise additional capital through future equity or debt transactions to continue our drilling activities and other project developments.

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 provide no assurance 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. 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 geologic formations;
- equipment failures or accidents;
- title imperfections;
- tropical storms, hurricanes and other adverse weather conditions, which are common in the Gulf of Mexico during certain times of the year;
- regulatory requirements; and
- equipment and labor shortages resulting in cost overruns.

Additionally, 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.

We plan to conduct most of our near-term exploration and development activities on deep shelf prospects in the shallow waters of the Gulf of Mexico, an area that has had limited historical drilling activity due, in part, to its geologic complexity. Deeper targets are more difficult to detect with traditional seismic processing and the expense of drilling deep shelf wells and the risk of mechanical failure is significantly higher because of the higher temperatures and pressure found at greater depths. Our exploratory wells require significant capital expenditures (typically ranging between $15-$20 million, net to our interests) before we can ascertain whether they contain commercially recoverable oil and natural gas reserves. Prior experience also suggests that the gross drilling costs for deep shelf exploratory wells can potentially exceed as much as $50 million per well. 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.

A significant portion 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 geologic and geophysical costs and the costs of unsuccessful exploration wells as they are incurred, rather than capitalizing these costs up to a specified limit as permitted pursuant to 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 enable us to achieve or sustain positive earnings or cash flows from operations in the future.

To sell our natural gas and oil we depend upon the availability, proximity and capacity of natural gas gathering systems, pipelines and processing facilities, which are owned by others.

To sell our natural gas and oil we depend upon the availability, operation and capacity of natural gas gathering systems, pipelines and processing facilities, which are owned by others. If these 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.

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 a precise 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;
- the effects that hedging contracts may have on our sales of oil and natural gas; and
- the assumed effects of government regulation and taxation.

These factors and assumptions are difficult to predict and may vary considerably from actual results. In addition, reserve engineers may make varying 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 in our estimated reserves, which may be substantial. 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, 2007, without any adjustment to normalize those prices and costs based on variations over time either before or after this 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 oil and gas purchasers; and
- changes in governmental regulations and taxation.

In addition, the 10 percent discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor to be used in determining market values of proved oil and gas reserves. Changes in market interest rates at various times and the risks associated with our business or the oil and gas industry 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 covering the future costs of exploring and developing certain portions of our oil and gas 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 either 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 related to 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 operators or 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 crude 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 the trading prices of our securities.

If crude 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 our results of operation and financial condition and 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.

Hedging our production may result in losses.

In connection with the financing of the acquisition of the Newfield properties, we were required to hedge a portion of our reasonably estimated oil and natural gas production from our proved developed producing oil and gas properties for the years 2008 through 2010. This hedging position reduces our exposure to fluctuations in the market prices of oil and natural gas. We may review future opportunities to hedge a portion of our oil and natural gas production. 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;
- require bonds or the assumption of other financial responsibility requirements to cover drilling contingencies and well plugging and abandonment costs;
- impose substantial liabilities for pollution resulting from our operations; and
- require capital expenditures for pollution control equipment.

New environmental laws or changes in existing laws or their enforcement may be enacted and such new laws or changes may require significant expenditures by us. 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 injury, property damage, oil spills, natural resource damages, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. Liability under environmental laws can be imposed retroactively and without regard to whether we knew of, or were responsible for, the presence of contamination on properties that we own or operate. Such liability may also be joint and several, meaning that the entire liability may be imposed on a party without regard to contribution. 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 results of operations and financial condition. 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.

The crude oil and natural gas exploration business is very competitive, and many of our competitors are larger and financially stronger than we are.

The business of oil and natural gas exploration, development and production is intensely competitive. 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. For example, these competitors may be better positioned to:

- access capital bearing a lower cost;
- acquire producing properties and proved undeveloped acreage;
- 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 geologic 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.

We have historically maintained insurance for our operations, including liability, property damage, business interruption, limited coverage for sudden and accidental environmental damages and other insurance. We no longer carry business interruption insurance as the increased level of hurricane activity in the Gulf of Mexico during 2005 increased premiums to levels that are currently no longer cost beneficial. Any insurance that we purchase will not provide protection against all potential liabilities incident to the ordinary conduct of our business. Moreover, any insurance we maintain will be subject to coverage exclusions, 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 a material casualty loss that is not covered by insurance would adversely affect our results of operations and financial condition.

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

Our strategy of concentrating our exploration and production activities 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:

- tropical storms and hurricanes, which are common in the Gulf of Mexico during certain times of the year;
- 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 results of operations and financial condition.

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, as well as other third-party consultants with extensive experience and expertise in:

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

Our ability to retain our senior officers, other key employees and our third party consultants, 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.

Risk Relating to the Main Pass Energy Hub™ Project

We may not be able to obtain the necessary financing to complete the development of the MPEH™ project, and any such financing may also be limited by restrictions or other conditions contained in our existing credit agreements, potentially preventing our continued operations or development of the MPEH™ project.

The development of the MPEH™ project and the conversion of our former sulphur facilities at Main Pass into a LNG receipt and processing terminal will 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. Additionally, to the extent such financing is obtained, it may be limited by restrictions or other conditions contained in our existing credit agreements.

Our interest in the proposed LNG terminal project will be reduced if third parties exercise their options to acquire passive equity interests in our MPEH™ project, and may be further reduced by any financing arrangements that we may enter into with respect to this project.

K1 USA Ventures, Inc. and K1 USA Energy Production Corporation, subsidiaries of k1 Ventures Limited (collectively, K1), have the option, exercisable upon the closing of any project financing arrangements, to acquire up to 15 percent, collectively, of our equity interest in the MPEH™ project by agreeing prospectively to fund collectively 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 the same basis as K1. 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 potential control of, the MPEH™ project.

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

Fluctuations in energy prices or the supply of natural gas could be harmful to the operations of our LNG terminal at our Main Pass facilities.

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 negatively 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 our Main Pass facilities, the operations of such facility would be subject to the inherent risks associated with those operations, including explosions, pollution, fires, 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 other 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 international 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 for importation into the United States market.

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

Although there are currently a limited number of LNG terminal facilities operating in North America, if substantial construction costs and environmental concerns associated with the development of these facilities decrease in the future, companies may begin to pursue the development of infrastructure, both onshore and offshore, to serve the North American natural gas market. In this event, certain competitors may have greater name recognition, larger staffs and greater financial, technical and marketing resources than we do, allowing these companies to develop potentially superior LNG receiving terminal projects. If the number of our competitors in this market increases, creating excess capacity for such terminals, such excess would likely lead to decreased prices for services offered by these terminals. Because of the substantial likelihood that we will have significant debt service obligations, any price decreases could potentially impact us more severely than our competitors with greater financial resources.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

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 February 29, 2008, 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	69	Co-Chairman of the Board
Richard C. Adkerson	61	Co-Chairman of the Board
Glenn A. Kleinert	65	President and Chief Executive Officer
C. Howard Murrish	67	Executive Vice President

Name	Age	Position or Office
Nancy D. Parmelee	56	Senior Vice President, Chief Financial Officer and Secretary
Kathleen L. Quirk	44	Senior Vice President Finance and Business Development and Treasurer
John G. Amato	64	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 currently serves as Executive Vice President, Chief Financial Officer and Treasurer of FCX, and has held those offices since March 2007, December 2003 and February 2000, respectively. She also served as Senior Vice President of FCX from December 2003 to March 2007, as Vice President from February 1999 to December 2003, and as Assistant Treasurer from November 1997 to February 1999. Ms. Quirk currently serves as Vice President and Treasurer of Freeport-McMoRan Energy LLC, and has held the offices of Vice President and Treasurer since February 1999 and April 2003, respectively. She had also previously served as a Treasurer of Freeport-McMoRan Energy LLC 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.

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 certifications of each of our CEO and CFO required under Section 302 of the Sarbanes-Oxley Act of 2002 have been filed as exhibits to this Form 10-K. The following table sets forth, for the period indicated, the range of high and low sales prices, as reported by the NYSE.

	2007		2006	
	High	Low	High	Low
First Quarter	$15.53	$11.01	$21.12	$16.77
Second Quarter	15.73	12.51	19.63	14.37
Third Quarter	17.93	12.94	19.42	16.60
Fourth Quarter	15.81	10.70	18.46	13.95

As of February 29, 2008 there were 7,654 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. Currently, our debt agreements prohibit our ability to pay dividends on our common stock.

Issuer Purchases of Equity Securities

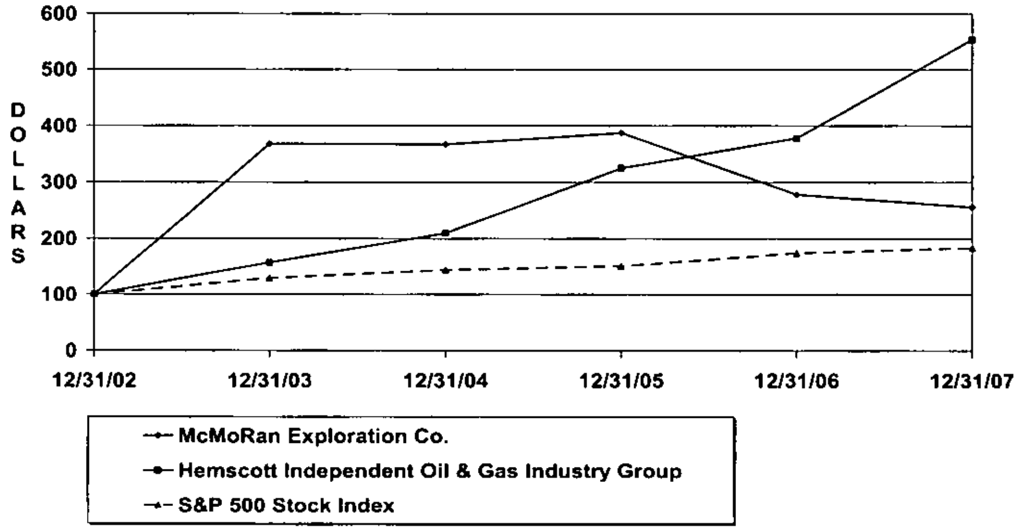
In 1999, our Board of Directors approved an open market share purchase program for up to 2.0 million shares of our common stock. In 2000, the Board of Directors authorized the purchase of up to an additional 0.5 million shares under the program. The program does not have an expiration date. No shares were purchased during the three years ending December 31, 2007. Approximately 0.3 million shares remain available for purchase under the program.

Performance Graph

The information included under the caption "Performance Graph" in this Item 5 of this Form 10-K is not deemed to be "soliciting material" or to be "filed" with the SEC or subject to Regulation 14A or 14C under the Securities Exchange Act of 1934 or to the liabilities of Section 18 of the Securities Exchange Act of 1934, and will not be deemed to be incorporated by reference into any filings we make under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent we specifically incorporate it by reference into such a filing.

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 2003 through 2007. This comparison assumes $100 invested on December 31, 2002 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,					
	2002	2003	2004	2005	2006	2007
McMoRan Exploration Co.	$100.00	$ 367.65	$ 366.67	$ 387.65	$ 278.82	$ 256.67
Hemscott Independent Oil & Gas Industry Group	100.00	155.97	209.55	325.27	378.00	553.99
S&P 500 Stock Index	100.00	128.68	142.69	149.70	173.34	182.87

* 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, 2007. 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.

	2007[a]	2006	2005	2004	2003
Financial Data	(Financial Data in Thousands, Except Per Share Amounts)				
Years Ended December 31:					
Revenues [b]	$ 481,167	$ 209,738	$ 130,127	$ 29,849	$ 17,284
Depreciation and amortization	256,007	104,724	25,896	5,904	14,112
Exploration expenses	58,954	67,737	63,805	36,903	14,109
Start-up costs for Main Pass Energy Hub™ [c]	9,754	10,714	9,749	11,461	11,411
Exploration expense reimbursement [d]	-	(10,979)	-	-	-
Litigation settlement [e]	-	(446)	12,830	-	-
Insurance recovery [f]	(2,338)	(3,306)	(8,900)	(1,074)	-
Operating income (loss)	3,509	(32,567)	(22,373)	(43,940)	(38,947)
Interest expense, net	66,366	10,203	15,282	10,252	4,599
Loss from continuing operations	(63,561)	(44,716)	(31,470)	(52,032)	(41,847)
Income (loss) from discontinued operations [g]	3,827	(2,938)	(8,242)	361	(11,233)
Cumulative effect of change in accounting principle	-	-	-	-	22,162[h]
Net loss applicable to common stock	(63,906)	(49,269)	(41,332)	(53,313)	(32,656)
Basic and diluted net loss per share of common stock:					
Continuing operations	$ (1.97)	$ (1.66)	$ (1.35)	$ (2.85)	$ (2.62)
Discontinued operations	0.11	(0.10)	(0.33)	0.02	(0.68)
Cumulative effect of change in accounting principle	-	-	-	-	1.33
Basic and diluted net loss per share	$ (1.86)	$ (1.76)	$ (1.68)	$ (2.83)	$ (1.97)
Average basic and diluted common shares outstanding	34,283	27,930	24,583	18,828	16,602
At December 31:					
Working capital (deficit)	$ (221,302)	$ (25,906)	$ 67,135	$ 175,889	$ 83,143
Property, plant and equipment, net	1,503,359	282,538	192,397	97,262	26,185
Total assets	1,715,288	408,677	407,636	383,920	169,280
Oil and gas reclamation obligations	294,737	25,876	26,484	14,429	7,273
Long-term debt	689,000	244,620	270,000	270,000	130,000
Mandatorily redeemable convertible preferred stock	-	29,043	28,961	29,565	30,586
Stockholders' equity (deficit)	$ 372,229	$ (68,443)	$ (86,590)	$ (49,546)	$ (84,593)

a. Amounts in 2007 primarily reflect the acquisition of oil and gas properties from Newfield Exploration Company, the financing transactions associated with the funding of the acquisition, subsequent refinancing transactions, the assumption of related reclamation obligations and the operating results for the period of August 6, 2007 through December 31, 2007 (Notes 2, 5, 6, 8 and 14).

b. Includes service revenues totaling $5.9 million in 2007, $13.0 million in 2006, $12.0 million in 2005, $14.2 million in 2004 and $1.2 million in 2003. The service revenues primarily reflect recognition of the management fees received associated with our exploration venture activities (Note 3), oil processing and other third party management fees and reimbursements of standard industry overhead fees (Note 1).
c. 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 4 and 5).
d. Reflects $20.0 million received upon inception of an exploration agreement in fourth quarter of 2006 (Note 3). 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.
e. Reflects settlement of class action litigation case, net of insurance proceeds (Note 13).
f. Reflects proceeds received in connection with our oil and gas hurricane-related insurance claims (Note 5).
g. Amounts include charges for modification of previously estimated reclamation plans for remaining closed sulphur 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 ($4.6 million in 2007, $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 13). The amount for 2003 includes a $5.9 million estimated loss on the disposal of certain sulphur assets, which were sold during 2004.
h. Reflects implementation of Statement of Financial Accounting Standard No. 143 "*Accounting for Asset Retirement Obligations*" effective January 1, 2003 (Note 1).

	2007[a]	2006	2005	2004	2003
Operating Data					
Sales Volumes:					
Gas (thousand cubic feet, or Mcf)	38,994,000	14,545,600	7,938,000	1,978,500	2,011,100
Oil (barrels) [b]	2,380,500	1,379,300	716,400	61,900	107,600
Plant products (equivalent barrels)[c]	358,900	178,700	106,700	22,900	20,700
Average realization:					
Gas (per Mcf)	$ 7.01	$ 7.05	$ 9.24	$ 6.08	$ 5.64
Oil (per barrel)	76.55	60.55	53.82	39.83	30.76

a. For the period from August 6, 2007 to December 31, 2007, the sales volumes associated with the acquired Newfield properties totaled 25.5 Bcf of natural gas and approximately 1,476,500 barrels of oil and condensate.
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 (Note 5). Oil sales from Main Pass totaled 558,600 barrels in 2007, 779,000 barrels in 2006, 436,000 barrels in 2005, and 4,200 barrels in 2003. 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. Revenues from plant products (ethane, propane, butane, etc.) totaled $19.3 million in 2007, $9.6 million in 2006, $5.0 million in 2005, $0.6 million in 2004 and $0.8 million in 2003.

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

You should read the following discussion in conjunction with our consolidated financial statements and the related discussion of "Business and Properties" included in Items 1. and 2. of 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 area. We have one of the largest acreage positions in the shallow waters of the Gulf of Mexico and Gulf Coast areas, which are our regions of focus. Our focused strategy enables us to efficiently use our strong base of geological, engineering and production experience in the area in which we have operated for more than 35 years. We also believe that our increased scale of operations in the Gulf of Mexico will provide synergies and a strong platform from which we will be able to pursue our business strategy. Our oil and gas operations are conducted through McMoRan Oil & Gas LLC (MOXY), our principal operating subsidiary. In addition to our oil and gas operations, we are pursuing a multifaceted energy services development of the Main Pass Energy Hub™ (MPEH™) project, including the development of a potential LNG regasification and storage facility through our other wholly-owned subsidiary, Freeport-McMoRan Energy LLC (Freeport Energy). For additional information regarding our business and operations, see Items 1. and 2. entitled "Business and Properties" of this Form 10-K.

Business Strategy

We expect to continue to pursue growth in reserves and production through the exploration, exploitation and development of our existing oil and gas prospects and new potential prospects. Exploration will continue to be the focus in efforts to maximize value. With our recent acquisition of all of the proved property interests and related assets of Newfield Exploration Company (Newfield) located on the outer continental shelf of the Gulf of Mexico and our recent discoveries, we also have additional opportunities to create values through exploration development and exploitation of these properties.

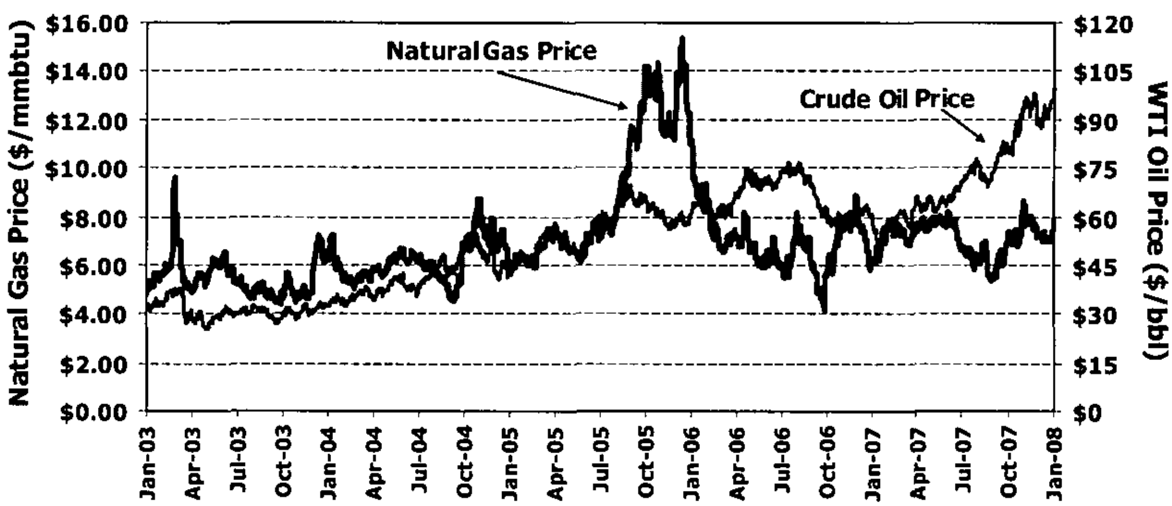
Our technical and operational expertise is primarily in the Gulf of Mexico. We leverage this expertise by attempting to identify exploration opportunities with high potential, high risk drilling prospects in this region. We continue to focus on enhancing reserve and production growth in the Gulf of Mexico by emphasizing and applying advanced geological, geophysical and drilling technologies. Our exploration strategy, which we refer to as the "deeper pool concept," involves exploring prospects that lie below shallower intervals on the Deep Miocene geologic trend that have had significant past production. A significant advantage to our "deeper pool" exploration strategy is that infrastructure is in most cases already available, meaning discoveries generally can be brought on line quickly and at lower development costs. We believe our techniques for identifying reservoirs using structural geology augmented by 3-D seismic data will enable us to identify and exploit additional "deeper pool" prospects at drilling depths exceeding 15,000 feet. For additional information regarding our business strategy, see Items 1. and 2. "Business and Properties" of this Form 10-K.

Implementing our business strategy will require significant expenditures during 2008 and beyond. During 2007 we spent $153.2 million on capital-related projects primarily associated with our exploration activities and the subsequent development of our related discoveries. Our exploration, development and other capital expenditures for 2008 are expected to approximate $225 million, including $40 million of carryover costs from 2007, $95 million for development costs and $90 million for Flatrock, Blackbeard and other exploration opportunities. These expenditures also may increase as additional exploration opportunities are presented to us or to fund development costs associated with additional successful wells. We also plan to spend approximately $80 million in 2008 to abandon and remove oil and gas structures from the Gulf of Mexico, the substantial majority of this amount is associated with structures acquired in the Newfield transaction that were severely damaged by hurricanes in 2005. We plan to fund our exploration, development and reclamation activities with our operating cash flow and availability under our senior secured revolving credit facility (see "Capital Resources and Liquidity — Senior Secured Revolving Credit Facility" below). We will require commercial arrangements for the MPEH ™ project to obtain financing, which may be in the form of additional debt or equity transactions. The ultimate outcome of our efforts to obtain additional financing 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 and Oil Market Environment

North American natural gas averaged $7.11 per MMbtu during 2007. High storage levels generally limited upward price movements during the winter months; however in late February prices increased to over $9 per MMbtu and the spot price for natural gas was $10.23 per MMbtu on March 13, 2008, reflecting a recent decline in storage inventories. The market fundamentals for oil reached new historical highs of approximately $110 per barrel during the first quarter of 2008 and averaged over $90 per barrel in fourth quarter 2007, reflecting market concerns over potential supply reliability combined with strong global demand. The average price for crude oil was $72.45 per barrel in 2007 and was $110.33 per barrel as of March 13, 2008. Future oil and natural gas prices are subject to change and these changes are not within our control (see Item 1A. "Risk Factors" included in this Form 10-K). Our average realizations during 2007 were $7.01 per Mcf of natural gas and $76.55 per barrel for oil, including the sale of sour crude oil produced at Main Pass.

Natural Gas and Crude Oil Prices - January 2003-February 2008



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 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 from traditional sources of supply. Accordingly, industry experts project that, over the next two decades, non-traditional sources of natural gas, such as Alaska, the Canadian Arctic, the deep energy shelf, tight sands gas, shale gas, coal seam methane and imported liquefied natural gas, or LNG, will provide a significantly larger share of the supplies to the U.S. We believe that we are well positioned to pursue two of these alternative supply sources, 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 however, LNG imports are expected to grow as a result of declining domestic natural gas production. As a result, new LNG regasification facilities may be developed if the construction costs and environmental concerns associated with the development of these facilities decrease in the future. Development of LNG facilities often requires long lead times to secure environmental permits and other regulatory approvals, as well as project financing.

OPERATIONAL ACTIVITIES

On August 6, 2007, we acquired substantially all of the proved property interests and related assets of Newfield located on the outer continental shelf of the Gulf of Mexico for total cash consideration of approximately $1.1 billion and the assumption of the related reclamation obligations. This acquisition had an effective date of July 1, 2007 and significantly expanded our scale of operations. For additional information regarding the acquisition of the Newfield properties, see Note 2 and "Business — Business Strategy — Newfield Property Acquisition" in Items 1. and 2. "Business and Properties" of this Form 10-K.

In late July 2007, in connection with the closing of this transaction, we entered into certain derivative contracts as required under our debt financing arrangements with respect to a portion of our anticipated production for the years 2008 through 2010. For additional information regarding our oil and gas derivative contracts see Note 7.

Exploration Agreements

In 2004, we and a private exploration and production company (exploration partner) jointly committed 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 reached 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. We and our private exploration partner have continued 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 management fees of $9.0 million in 2006 and $7.0 million in 2005. We recognized these management fees as service revenue in our accompanying consolidated statements of operations. 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 entry into a new exploration agreement with Plains Exploration & Production Co. (Plains) as described below.

In the fourth quarter of 2006, we entered into an exploration agreement with Plains whereby Plains obtained the right to participate in various exploration prospects in limited areas being explored by us. None of the properties we acquired from Newfield are subject to our agreement with Plains. As of December 31, 2007, Plains has participated in six prospects under the terms of this exploration agreement. Under the agreement, Plains paid us $20.0 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 line item titled "Reimbursement of exploration expense" and 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 prospects covered by this agreement and is included within investing activities in the accompanying consolidated statements of cash flow.

Oil and Gas Activities

Since 2004, we have participated in 17 discoveries on 32 prospects that have been drilled and evaluated, including four discoveries announced in 2007. We have commenced production from 16 of these discoveries as of March 14, 2008. During 2007, we announced a potentially significant discovery called Flatrock on OCS Block 310 at South Marsh Island Block 212. Early in 2008, we announced two additional successful wells at the Flatrock field. The Flatrock No. 1 well commenced production on January 28, 2008 and at March 14, 2008 was producing at a rate of approximately 48 MMcf/d and 845 barrels of condensate per day, approximately 12 MMcfe/d net to us. The Hurricane Deep discovery commenced production on January 24, 2008 and at March 14, 2008 was producing at a gross rate of approximately 22 MMcfe/d, 5 MMcfe/d net to us. Three additional prospects are not yet fully evaluated. Our aggregate investment in the these wells at December 31, 2007 totaled $67.8 million, including $22.9 million for the Blueberry Hill well, $15.3 million for the Mound Point South well, both located at Louisiana State Lease 340, and $29.6 million for the JB Mountain Deep well located at South Marsh Island Block 224. We expect to commence production from the recent Cottonwood Point discovery well at Vermilion Block 31 in the second quarter of 2008. For additional information regarding our Flatrock discovery as well as our other recent discoveries and development activities, see the "Properties — Oil and Gas Activity — Discoveries and Development Activities" in Items 1. and 2. "Business and Properties" of this Form 10-K. Our near-term exploratory wells are as follows:

	Working Interest (%)	Net Revenue Interest (%)	Prospect Acreage [a]	Water Depth (feet)	Proposed Total Depth [b] (feet)	Recent Depth (feet)	Spud Date
South Marsh Island Block 212 "Flatrock No. 2" [c]	25.0	18.8	3,805	10	[c]	17,684 [c]	October 7, 2007
South Marsh Island Block 212 "Flatrock No. 3"	25.0	18.8	3,805	10	18,800	17,100	November 5, 2007
South Timbalier Block 168 "Blackbeard West"	26.8	22.3	24,512	70	31,200	30,067	March 2008
Louisiana State Lease 340 "Mound Point East"	40.7 [d]	23.2	2,385	5	18,050	N/A	Second Quarter 2008

a. Gross acres encompassing prospect to which we retain exploration rights.
b. Planned target vertical depth, which is subject to change.
c. The Flatrock No. 2 well has been drilled to its total depth and completion activities are in progress with initial production expected by mid-year 2008.
d. Reflects working interest before casing point elections, which may reduce working interest to 32.5 percent.

Acreage Position

As of December 31, 2007, we owned or controlled interests in 603 oil and gas leases in the Gulf of Mexico and onshore Louisiana and Texas covering 1.52 million gross acres (0.64 million acres net to our interests). Our acreage position includes 1.30 million gross acres (0.57 million acres net to our interest) located on the outer continental shelf of the Gulf of Mexico. We own leasehold interests to approximately 0.5 million gross acres, 0.1 million net to our interests, that are scheduled to expire in 2008. We also hold potential reversionary interests in oil and gas leases that we have farmed-out or sold to other oil and gas exploration companies but that would partially revert to us upon the achievement of a specified production threshold or the achievement of specified net production proceeds. For more information regarding our acreage position, see Note 3 and "Properties — 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 152 MMcfe/d during 2007 compared with 65 MMcfe/d in 2006 and 36 MMcfe/d in 2005. Our fourth quarter 2007 production, the first full quarter including results from the acquired Newfield properties, averaged 295 MMcfe/d. Our average net daily production for 2008 is expected to approximate 270 MMcfe/d, with our net production averaging approximately 280 MMcfe/d for the two month period ending February 29, 2008. As discussed above in "Oil and Gas Activities," production from both the Flatrock and Hurricane Deep wells commenced in January 2008. Production estimates may change as additional information with respect to the Flatrock and/or other exploration prospects is received and evaluated.

MAIN PASS ENERGY HUB™ PROJECT

In addition to our oil and gas operations, we are pursuing a multifaceted energy services development of the MPEH™ project, including the potential development of an LNG regasification and storage facility through Freeport Energy. The MPEH™ project is located offshore in the Gulf of Mexico, 38 miles east of Venice, Louisiana at our Main Pass facilities. Following an extensive review, in January 2007, the Maritime Administration approved our license application for the MPEH™ project. The MPEH™ facility is approved with a capacity 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 of natural gas per day, including gas from storage, to the U.S. market. As of December 31, 2007, we have incurred approximately $45.6 million of cash costs associated with our pursuit of establishment of MPEH™, which includes the advancement of license process and the pursuit of commercial and financing arrangements for the project. As of December 31, 2007, we have recognized a liability of $10.5 million relating to the future reclamation of the MPEH™ related facilities. 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.

For additional information regarding the MPEH™ project, including preliminary capital expenditure estimates, see "Business — Business Strategy — Main Pass Energy Hub™ Project" in Items 1. and 2. "Business and Properties" of this Form 10-K. Also see Notes 4 and 5 regarding information about transactions that may reduce our future ownership interest in the MPEH™ project and our oil facilities at Main Pass.

RESULTS OF OPERATIONS

Our only segment is "Oil and Gas." We are pursuing a new segment, "Energy Services," whose start-up activities are reflected as a single expense line item within consolidated statements of operations under the caption "Start-up Costs for Main Pass Energy Hub™." 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).

Our future operating results may continue to be adversely affected by our significant planned exploration activities and the start-up costs associated with establishing the MPEH™, which include permitting fees and costs associated with the pursuit of commercial arrangements for the project. Additionally, energy insurance market conditions have negatively affected our operating results in 2007. Property insurance coverage premiums have significantly increased over amounts paid two years ago while the related coverage generally has higher deductibles and more restrictive terms.

Our operating results have changed substantially following the acquisition of the Newfield properties. Our operating income for 2007 totaling $3.5 million includes the results from the acquired properties beginning on August 6, 2007. The summarized operating results for acquired properties for the period of August 6, 2007 through December 31, 2007 are as follows (in thousands):

Revenues:	
Oil and natural gas	$ 290,856
Service	4,557
Total revenues	295,413
Cost and Expenses:	
Production and delivery costs	57,099[a]
Depreciation and amortization	170,012
Exploration expenses	112[b]
General and administrative expenses	2,463[c]
Total costs and expenses	229,686
Operating income	$ 65,727

a. Includes lease operating expenses of $36.7 million, $6.8 million for workover costs, $11.8 million for well insurance expense and $1.8 million for transportation, production taxes and other related costs.
b. Excludes $13.0 million in seismic data costs incurred that were not allocated to the acquired properties.
c. Only includes cost directly allocated to the Newfield properties and excludes all compensation costs associated with newly hired employees, which are not allocated to the acquired properties. Amounts primarily reflect costs associated with information systems implementations in the fourth quarter of 2007 and rent expense for our new office space in Houston, Texas.

In addition to the revenues and expenses from the acquired properties, our 2007 operating income reflects (a) exploration expenses of $59.0 million, which includes $13.0 million in seismic data costs, primarily associated with the purchased acreage from Newfield and $22.8 million of nonproductive exploratory well drilling and related costs; (b) an impairment charge of $13.6 million to write off the remaining net book value of the Cane Ridge field at Louisiana State Lease 18055; (c) $9.8 million of start-up costs associated with MPEH™; and (d) an unrealized loss of $5.2 million associated with the mark-to-market adjustment for our oil and gas derivative contracts.

Our operating loss during 2006 totaled $32.6 million, which included a $21.9 million loss associated with our oil and gas operations and $10.7 million of start-up costs for the MPEH™ project. Our 2006 oil and gas operating results reflect significantly higher revenues ($209.7 million) than in 2005 ($130.1 million), partially offset by corresponding increases in 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 fields to their estimated fair values at December 31, 2006. Our oil and gas results were further reduced by $67.7 million of exploration costs, 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. 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.

Oil and Gas Operations – Year-to-Year Comparisons

As shown in the table on the previous page, the acquisition of the oil and gas properties from Newfield had a significant impact on our operating results for the year ended December 31, 2007.

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

	2007	2006
Oil and natural gas revenues – prior year period	$ 196,717	$ 118,176
Increase (decrease)		
Price realizations:		
Natural gas	6,421	(31,829)
Oil and condensate	6,725	8,953
Sales volumes:		
Natural gas	(7,215)	61,032
Oil and condensate	(15,702)	36,012
Properties acquired from Newfield	290,856	-
Plant products revenue	(2,058)	4,545
Other	(494)	(172)
Oil and natural gas revenues - current year period	$ 475,250	$ 196,717

See Item 6. "Selected Financial Data" 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, 2007.

Our oil and natural gas sales volumes totaled 55.5 Bcfe in 2007, 23.9 Bcfe in 2006 and 12.9 Bcfe in 2005. The increase in 2007 from 2006 reflects the acquisition of the oil and gas properties from Newfield offset by a 12 percent decrease in production from our legacy properties. The increase in 2006 production over amounts in 2005 primarily reflected the commencement of production from 14 additional wells. Average realizations received for oil sold during 2007 increased by 9.9 percent over amounts received in 2006, which increased 12.5 percent over amounts received in 2005 (see "—North American Natural Gas and Oil Market Environment" above). Average realizations for natural gas sold during 2007 increased 6.7 percent from amounts received during 2006. Average realization for natural gas decreased 24 percent from amounts received during 2005 when hurricanes significantly impacted the Gulf of Mexico resulting in record high natural gas prices.

Our 2007 revenues included $19.3 million of plant product sales associated with approximately 358,900 equivalent barrels of oil and condensate received for products (ethane, propane, butane, etc.) recovered from the processing of our natural gas. The amounts of plant product sales totaled $9.6 million from 178,700 equivalent barrels during 2006 and $5.0 million from 106,700 equivalent barrels in 2005. The increase in plant product revenues was directly related to the properties acquired from Newfield in 2007. Plant product revenues increased in 2006 primarily reflecting new production from the Hurricane field at South Marsh Island Block 217 and Long Point field at Louisiana State Lease 18091.

Our service revenues totaled $5.9 million in 2007, $13.0 million in 2006 and $12.0 million in 2005. The decrease primarily reflects the conclusion of our multi-year exploration venture with a private partner (see "Operational Activities—Exploration Agreements" above and Note 1) and the termination of third party oil and gas processing fees at Main Pass. These decreases were partially offset by additional production and handling fees from the processing of third party production and reimbursements of standard industry overhead fees associated with the properties acquired from Newfield in 2007.

Production and delivery costs. The following table reflects our production and delivery costs for the years ended December 31, 2007, 2006 and 2005 (in millions, except per Mcfe amounts):

	2007	Per Mcfe	2006	Per Mcfe	2005	Per Mcfe
Lease operating expense	$ 69.8	$1.26	$30.4	$1.27	$19.3	$1.50
Workover costs	19.7	0.35	4.5	0.19	1.3	0.10
Insurance	23.2	0.42	8.5	0.36	2.1	0.16
Transportation and production taxes	9.1	0.16	5.1	0.21	2.5	0.20
Other	0.3	0.01	4.6	0.19	4.4	0.34
Total production and delivery costs	$122.1	$2.20	$53.1	$2.22	$29.6	$2.30

Our higher lease operating expense reflects increased production over the three year period ended December 31, 2007, including the acquisition of the Newfield properties in August 2007. Our workover costs during 2007 primarily reflect operations at the Cane Ridge, King Kong, Blueberry Hill, Eugene Island Block 97 No. 3 and the Eugene Island Block 193 C-1 and C-2 wells. During 2006, our workover costs are related primarily to our attempts to restore production from the Minuteman well at Eugene Island Block 213 (Note 1) and the Hurricane No. 1 well at South Marsh Island Block 217.

Our insurance costs increased significantly following the mid-year 2006 renewal of our property insurance policies, which reflected the effects of the 2005 hurricanes on the insurance industry as well as the increased number of our producing fields and drilling activities during 2006. The amounts during 2007 also reflect incremental insurance costs associated with coverage on the properties acquired from Newfield. Our production taxes have increased over the prior year reflecting the commencement of production from new wells onshore Louisiana, specifically the Point Chevreuil and Laphroaig wells located in St. Mary, Parish, Louisiana. In 2006, we had approximately $4.3 million of repair costs associated with hurricane-related damages associated with Hurricane Katrina with the majority of such costs being incurred at Main Pass 299 ($3.6 million). In 2005, we had approximately $3.9 million of repair costs associated with hurricane-related damages incurred at Main Pass 299 associated with Hurricane Ivan.

Depletion, depreciation and amortization expense. The following table reflects the components of our depletion, depreciation and amortization expense for the years ended December 31, 2007, 2006 and 2005 (in millions, except per Mcfe amounts):

	2007	Per Mcfe	2006	Per Mcfe	2005	Per Mcfe
Depletion and depreciation expense	$228.5	$4.12	$ 69.4	$2.91	$24.5	$1.90
Accretion expense	13.9	0.25	2.1	0.08	1.4	0.11
Impairment charges/losses	13.6	0.25	33.2	1.39	-	-
Total depletion, depreciation and amortization expense	$256.0	$4.62	$104.7	$4.38	$25.9	$2.01

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 depletion, depreciation and amortization rates. The increase in our depletion, depreciation and amortization expense in 2007 over prior years primarily reflects our increased production from new producing properties and related production from the acquired Newfield properties.

We record accretion expense on our estimated discounted reclamation obligations. The increase over the prior year primarily reflects the effect from assumed reclamation obligations from the Newfield properties.

As further explained in Note 1, accounting rules require the carrying value of proved oil and gas property costs to 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 than anticipated oil and natural gas prices, decreased production, increased development, production 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.

During 2007, after our final attempts to reestablish production were unsuccessful at the Cane Ridge well at Louisiana State Lease 18055, we recorded a $13.6 million impairment charge to write off our remaining investment in the well. During 2006, because of significant uncertainty as to timing and probability of success of potential remedial operations at the Minuteman well at Eugene Island Block 213, we recorded a $12.2 million impairment charge to reduce our investment at December 31, 2006 to its then estimated fair value. 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. Production from the well commenced in January 2007 at reduced rates and in February 2007 the well was shut-in. Accordingly, based on our assessment that it would be unlikely that the proved reserves associated with this field would be fully recovered, we recorded a $21.0 million impairment charge to reduce our investment in the West Cameron Block 43 field to its then estimated fair value as of December 31, 2006 and recorded an additional $0.7 million of accretion expense to fully accrue the estimated reclamation costs.

The Pecos well located at West Pecan Island in Vermilion Parish, Louisiana commenced production in August 2006. Production rates subsequently decreased and we initiated remedial operations in an attempt to stimulate the well's production in the first quarter of 2007. These efforts were unsuccessful and we subsequently recompleted the well to the upper productive interval. After producing and depleting the reserves from the upper productive zone, we will consider drilling a sidetrack well to recover additional identified potential reserves. Our investment in the Pecos well totaled $5.7 million at December 31, 2007.

Since commencing production in August 2006, the King of the Hill well was producing reserves from the same reservoir from which competing wells are producing in adjacent lease blocks. During 2007, the well started producing significant water and the operator was unable to determine the source of the water. The operator has recently sidetracked the well to deepen the well to a new productive zone which is being competitively produced from an adjacent lease block. The well has been completed and perforated; however, additional issues have prevented the commencement of production. Following production from this new zone, we will evaluate the completion into the original producing interval. Our investment in the King of the Hill well was $8.4 million at December 31, 2007.

Exploration Expenses. Summarized exploration expenses are as follows (in millions):

	Years Ended December 31,		
	2007	2006	2005
Geological and geophysical, including 3-D seismic purchases [a]	$ 29.9 [b]	$ 15.2	$ 7.4
Dry hole costs	22.8 [c]	45.6 [d]	49.6 [e]
Insurance and other	6.3	6.9	6.8
	$ 59.0	$ 67.7	$ 63.8

a. Includes compensation costs associated with stock-based awards totaling $6.3 million in 2007, $8.1 million in 2006 and $1.1 million in 2005.
b. Includes $13.0 million of seismic data purchases primarily associated with the exploration acreage acquired from Newfield.
c. Includes nonproductive exploratory drilling and related costs primarily associated with the "Cas" well at South Timbalier Block 70 ($21.6 million).
d. Includes nonproductive exploratory drilling and related costs for wells at Grand Isle Block 18 ($7.0 million), Vermilion Block 54 ($7.8 million), Louisiana State Lease 18091 ($14.9 million), 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 West Cameron Block 95 ($2.7 million) and South Marsh Island Block 230 ($2.5 million), which were evaluated as nonproductive in January 2006.

e. Includes nonproductive exploratory well drilling and related costs at South Marsh Island Block 230 ($5.9 million) and West Cameron Block 95 ($10.8 million) during the fourth quarter of 2005. Nonproductive exploratory well costs during 2005 also included Louisiana State Lease 1706 ($9.8 million), South Timbalier Blocks 97/98 ($6.9 million), Louisiana State Lease 5097 ($12.1 million) and $1.3 million of well drilling costs at Vermilion Block 207 incurred after December 31, 2004. We also charged approximately $1.4 million of expiring leasehold costs to exploration expense in 2005.

Other Financial Results

Operating

Our general and administrative expenses totaled $28.0 million in 2007, $20.7 million in 2006 and $19.6 million in 2005. Our increased general and administrative costs in 2007 reflect increased personnel associated with administering the properties acquired from Newfield. We charged approximately $6.3 million of stock-based compensation costs to general and administrative expense during 2007 compared to $7.1 million in 2006 and $0.6 million in 2005. General and administrative expenses during 2006 benefited from a reduction in legal costs following settlement of class action litigation in the fourth quarter of 2005 (see 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.

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.

In 2007, we recorded $5.2 million in mark-to-market adjustments related to the fair values of our oil and gas derivative contracts. During the two months ended February 29, 2008, we have recorded an additional $37.4 million in losses associated with the change in fair value related to our oil and gas derivative contracts (Note 7).

Our operating results in 2007 included insurance recoveries totaling $2.3 million related to our Hurricane Katrina property loss claims. 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 299. Our 2005 operating results reflect receipt of $20.5 million of insurance proceeds related to our Main Pass claims following Hurricane Ivan in September 2004. Business interruption proceeds totaled $12.4 million with the remaining proceeds related to property and other damage including the modification of the storage and loading facilities.

Non-Operating

Interest expense, net of capitalized interest, totaled $66.4 million in 2007, $10.2 million in 2006 and $15.3 million in 2005. We capitalized interest totaling $6.3 million in 2007, $5.3 million in 2006 and $2.1 million during 2005. The increase in interest expense in 2007 is associated with the financing obtained to acquire the oil and gas properties from Newfield (see "— Capital Resources and Liquidity" below). Capitalized interest has fluctuated during the past three years to reflect the timing and amount of our oil and gas drilling and development activities.

Other income (expense) totaled ($0.7) million in 2007, ($1.9) million in 2006 and $6.2 million in 2005. Interest income for the three years ended December 31, 2007 totaled $2.2 million in both 2007 and 2006 and $6.1 million in 2005. Other expense in 2007 included the prepayment premium of $3.0 million to terminate our Senior Secured Term Loan (see "— Capital Resources and Liquidity—Senior Term Loan Agreement" below) partially offset by interest income. Other expense in 2006 reflected $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" below). Other income for 2005 primarily reflected higher interest income on our cash equivalent balances, which reflected the completion of two capital transactions in October 2004.

Discontinued Operations

Our discontinued operations resulted in income of $3.8 million in 2007 and losses of $2.9 million and $8.2 million in 2006 and 2005, respectively. The aggregate estimated closure costs for Port Sulphur approximates $9.6 million at December 31, 2007. We estimate that we will incur these remaining costs in 2008 under currently anticipated closure activities, which are subject to change pending regulatory approval. Insurance recoveries totaling $7.7 million have partially mitigated our previously incurred Port Sulphur closure costs. We recorded $3.5 million of these recoveries as a gain from discontinued operations in the fourth quarter of 2006 and the remaining $4.2 million in the first quarter of 2007. Our discontinued operations' results are summarized in Note 9.

In our June 2002 sale of substantially all the assets used in our sulphur transportation and terminaling business, we agreed to be responsible for certain related historical environmental obligations 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, 2007, we have paid approximately $0.2 million to settle certain claims related to these assumed liabilities. Although potential liabilities for these assumed environmental obligations may exist, no specific liability has been identified that we believe is reasonably probable to require us to fund any future amount. See Item 1A. "Risk Factors" included in this Form 10-K for more information with respect to these risks. At December 31, 2007, approximately $0.5 million 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 discontinued operations' working capital requirements and to provide potential funding for certain retained environmental obligations.

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,		
	2007	2006	2005
Continuing operations			
Operating	$ 219.0	$ 99.5	$ 78.2
Investing	(1,195.2)	(231.1)	(143.1)
Financing	974.6	22.8	1.2
Discontinued operations			
Operating	$ (11.4)	$ (4.3)	$ (4.7)
Investing	-	-	(0.1)
Financing	-	-	-
Total cash flow			
Operating	$ 207.6	$ 95.2	$ 73.5
Investing	(1,195.2)	(231.1)	(143.2)
Financing	974.6	22.8	1.2

Comparison of Year-To-Year Cash Flows

Operating Cash Flows

Compared with the prior year, operating cash flow from our continuing operations in 2007 primarily reflects increased oil and gas revenues reflecting production from the acquired Newfield properties partially reduced by working capital requirements associated with our operations and $10.6 million of payments for oil and gas property reclamation expenditures. Our 2006 operating cash flow increased over the comparable 2005 amount because of increased oil and gas revenues partially offset by increased working capital requirements and a $12.4 million net payment to settle class action litigation. Our operating cash flow during 2006 also reflected a $11.0 million net reimbursement of previously incurred exploration costs resulting from exploration agreements negotiated during 2006.

Cash used in our discontinued operations increased significantly during 2007 reflecting the ongoing reclamation activities associated with the closure of the inactive Port Sulphur, Louisiana facilities. We paid $3.5 million in reclamation costs associated with these facilities in 2007. Cash used in our discontinued operations slightly decreased during 2006 from 2005, which primarily reflected $3.1 million of reclamation costs paid for work performed at Port Sulphur as well as other increased caretaking costs related to the facility. We estimate that we will incur the remaining $9.6 million of estimated closure costs in 2008 under currently anticipated closure activities, which are subject to change pending regulatory approval (Note 9).

Investing Cash Flows

Our investing cash flow in 2007 reflects the acquisition of the Newfield properties for $1.05 billion, net of purchase price adjustments (Note 2), and capital expenditures of $153.2 million, representing our exploratory drilling and development costs. Our investing cash flows also reflect the release to us of $6.1 million of previously escrowed U.S. government notes, which we used to pay the semi-annual interest payments on our 5¼% convertible senior notes on April 6, 2007 and October 6, 2007.

Our investing cash flow in 2006 reflects capital expenditures of $252.4 million. Our investing cash flows also reflect the release to us of $16.5 million of previously escrowed U.S. government notes. 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 relates to the funding of the debt conversion transaction (see "— Debt Conversion Transactions" below).

Our investing cash flow 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 (Note 5). 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 "— Convertible Senior Notes" 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.

Financing Cash Flows

Cash flow from our financing activities during 2007 primarily reflect the funding of the acquisition price for properties from Newfield. At closing, we borrowed $800 million under a bridge loan agreement and $394 million under our senior secured revolving credit facility. In November 2007, we repaid the bridge loan following sales of shares of our 6¾% mandatorily redeemable preferred stock and common stock, which resulted in net proceeds of $450.6 million, and $300 million of 11.875% senior notes due 2014. Costs associated with these financing transactions totaled $30.6 million. Total net borrowings under our revolving credit facility totaled $245.3 million in 2007. In 2007, our cash flow from financing activities also reflect $10.4 million of proceeds from the exercise of stock based awards, including the exercise of warrants for 1.74 million shares (Note 5) and $1.1 million of preferred stock dividend payments. For more information regarding our 2007 financing transactions see "Senior Secured Revolving Credit Facility," "Unsecured Bridge Loan Facility," "Senior Term Loan Agreement," "11.875% Senior Notes, " "Convertible Senior Notes," "Debt Conversion Transactions" and "Equity Offerings" below.

Cash provided by our financing activities during 2006 primarily reflects $28.8 million of net borrowings under our revolving credit facility. 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 5% convertible preferred stock and proceeds of $0.4 million from the exercise of stock options.

Cash provided by our 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 5% convertible preferred stock.

Senior Secured Revolving Credit Facility

We amended and expanded our senior secured revolving credit facility (credit facility) on August 6, 2007 in connection with the closing of the acquisition of the Newfield properties (Note 2). The credit facility's borrowing base was increased to $700 million and matures on August 6, 2012. We used the credit facility to fund $394 million of the closing acquisition price for the Newfield properties, as well as repay the remaining $58.8 million outstanding on the bridge loan after applying proceeds from the concurrent equity and subsequent debt offerings completed in November 2007 (see "— 11.875% Senior Notes" and" —Equity Offerings" below). We expect to use the credit facility in the future for working capital and other general corporate purposes. At December 31, 2007, we had borrowings of $274.0 million and $100 million in letters of credit issued under the credit facility. The letters of credit support the reclamation obligations assumed in the acquisition of the Newfield properties. At December 31, 2007, our availability for additional borrowings under the credit facility totaled $266.0 million.

Availability under our credit agreement is subject to a borrowing base based on estimates of MOXY's oil and natural gas reserves, which is subject to redetermination by the lenders semi-annually each April 1 and October 1. The variable-rate facility is secured by (1) substantially all the oil and gas properties of MOXY and its subsidiaries and (2) a pledge of our ownership interest in MOXY and MOXY's 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 financial covenants and other restrictions customary for oil and gas borrowing base credit facilities.

The credit facility is also subject to a quarterly borrowing base reduction of $60 million which began in the fourth quarter of 2007. These quarterly reductions in the borrowing base will continue through the fourth quarter of 2008 and will total $300 million in the aggregate. The credit facility also required MOXY to hedge a portion our crude oil and natural gas production for 2008 through 2010 (Note 7).

Unsecured Bridge Loan Facility

On August 6, 2007, we entered into a credit agreement in conjunction with the acquisition of the Newfield properties. The credit agreement provided for an $800 million interim bridge loan facility (bridge loan). We borrowed the entire $800 million available under the bridge loan to partially fund the acquisition price. In November 2007, we used the net proceeds from the public offering of shares of our common stock, our 6¾% convertible preferred stock (see ""— Equity Offerings" below), our 11.875% senior notes due 2014 (see "—11.875% Senior Notes" below) as well as additional borrowings under our credit facility to fully repay and terminate the bridge loan. At that time, we also charged to expense the remaining unamortized deferred financing costs associated with the bridge loan totaling $17.9 million. The charge was partially offset by a $9.0 million reimbursement from our lenders of previously paid closing fees that were contractually reimbursable to us for retiring the bridge loan within 120 days of its origination (Note 6).

Senior Term Loan

In January 2007, we entered into a senior term loan agreement (term loan) (Note 6). The loan agreement provided for a five-year, $100 million second lien senior secured term loan facility, which was scheduled to mature in January 2012. At the closing of the acquisition of the Newfield properties, we repaid and terminated the term loan. In connection with this repayment, we paid a 3.0 percent ($3.0 million) prepayment premium. The prepayment premium was reflected as a charge to non-operating expense in our accompanying consolidated statement of operations.

11.875% Senior Notes

On November 14, 2007, we completed the offering and sale of $300 million of our 11.875% senior notes (senior notes). Net proceeds from the sale of the senior notes of approximately $292 million were used, along with additional borrowings on our credit facility, to repay the remaining approximate $350 million of the bridge loan that remained outstanding after application of the net proceeds from the concurrent offerings of shares of our common stock and 6¾% mandatory convertible preferred stock. Interest on the senior notes is payable semi-annually (May 15 and November 15). The senior notes are due on November 15, 2014. We may redeem some or all of these notes at our option at make-whole redemption prices prior to November 15, 2011, and afterwards at stated redemption prices (Note 6).

Convertible Senior Notes

Our debt related to convertible senior notes totaled $215.9 million at December 31, 2007, reflecting $100.9 million of 6% convertible senior notes due on July 2, 2008 and $115.0 million of 5¼% convertible senior notes due on October 6, 2011. Each series of convertible senior notes is convertible into shares of our common stock at the election of the holder at any time prior to maturity. The conversion prices are $14.25 per share for the 6% notes and $16.575 per share for the 5¼% notes (Note 6). Beginning on October 9, 2009, we have the option of redeeming the 5¼% notes for a price equal to 100 percent of the principal amount of the notes plus any accrued and unpaid interest on these 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.

These convertible notes are unsecured. However, we used a portion of the net proceeds at closing of each series of convertible notes to purchase U.S. government securities to secure the first six semi-annual interest payments that were placed into escrow. We purchased $21.2 million of these government securities for the 5¼% notes and $22.9 million for the 6% notes. Interest payments on the 5¼% are due on April 6 and October 6. Our last interest payment on the 6% notes is due July 2, 2008. In 2007, we used the last remaining escrowed funds to pay the interest on the 5¼% notes.

In 2006, a portion of then outstanding balances on these senior notes were converted to equity through privately negotiated transactions. In the first quarter of 2008, an additional $24.5 million of the 6% notes were converted to equity through privately negotiated transactions (see "Debt Conversion Transactions" below), reducing our balance to $76.4 million as of March 14, 2008. We intend to meet our 2008 repayment requirements under the 6% notes through operating cash flow, availability under our credit facility or other refinancing transactions.

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 each note's respective conversion price (see "— Convertible Senior Notes" above and Note 6). 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, 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.

In the first quarter of 2008, through a series of privately negotiated transactions, an aggregate of $24.5 million of our 6% convertible notes were converted into approximately 1.72 million shares of our common stock. In connection with these transactions, we paid an aggregate $0.7 million to induce the conversions. These payments will be reflected as non-operating expense in our first quarter 2008 statement of operations. These conversion transactions will reduce our interest expense by $0.7 million during the first half of 2008. We will consider opportunities to negotiate additional conversion transactions in the future (see "— Convertible Senior Notes" above).

Equity Offerings

On November 7, 2007, we completed a public offering of 16.9 million shares of our common stock at $12.40 per share and a concurrent public offering of 2.59 million shares of our 6¾% mandatory convertible preferred stock (6¾% preferred stock) with an offering price of $100 per share (Note 8). The net proceeds from these offerings, after deducting the underwriters' discounts, were approximately $450 million. These proceeds were used to partially repay the bridge loan used in connection with the acquisition of the Newfield properties.

Each share of the 6¾% preferred stock has a par value of $100 and is entitled to receive quarterly cash dividends at rate of $1.6785 per share, with the exception of the first dividend payment which was paid February 15, 2008 at $1.8375 per share. The 6¾% preferred stock is convertible into between 17.4 million and 20.9 million shares of our common stock, subject to anti-dilution adjustments. The 6¾% preferred stock will automatically convert on November 15, 2010. Holders may elect at any time before November 15, 2010 to convert at a conversion rate equal to 6.7204 shares of common stock for each share of 6¾% 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 (5% preferred stock) (Note 8). Dividends accrued on the 5% preferred stock totaled $0.7 million in 2007 and $1.5 million in 2006 and 2005. In the second quarter of 2007, we issued a call for the redemption of the 5% preferred stock, effective June 30, 2007. Prior to the effective redemption date, the holders of the 5% preferred stock elected to convert all of the approximate remaining 1.2 million shares of convertible preferred stock outstanding into approximately 6.2 million shares of our common stock. Each share of 5% preferred stock was converted into 5.1975 shares of our common stock, or an equivalent of $4.81 per share.

Contractual Obligations and Commitments

In addition to our accounts payable and accrued liabilities ($166.1 million at December 31, 2007), we have other contractual obligations and commitments that will require payments in 2008 and beyond.

The table below summarizes the maturities of our 6% and 5¼% convertible senior notes and debt, our expected payments for retiree medical costs (Notes 10 and 13), our current exploration and development commitments and our remaining minimum annual lease payments as of December 31, 2007 (in millions):

	Debt and Convertible Securities [a]	Interest Payments[b]	Retirement Benefits[c]	Oil & Gas Obligations[d]	Lease Payments[e]	Total
2008	$ 111.5	$ 69.7	$ 1.6	$ 72.7	$ 1.4	$ 256.9
2009	-	63.7	1.6	15.0	1.3	81.6
2010	-	63.7	1.6	15.0	1.2	81.5
2011	115.0	63.7	1.6	5.0	1.1	186.4
2012	274.0	48.5	1.5	5.0	1.1	330.1
Thereafter	300.0	66.8	6.9	5.0	1.7	380.4
Total	$ 800.5	$ 376.1	$ 14.8	$ 117.7	$ 7.8	$ 1,316.9

a. Amounts due upon maturity subject to change based on future conversions by the holders of the securities. Subsequent to December 31, 2007, through March 13, 2008 a total of $24.5 million of our 6% convertible senior notes was converted to equity through a series or privately negotiated transactions (see "Debt Conversion Transactions" above).
b. Reflects interest and unused commitment fees on the debt balances and availability as of December 31, 2007. Assumes a 6.98 percent effective annual interest rate on our credit facility and a 1.88 percent and 0.38 percent interest on outstanding letters of credit ($100 million) and unused commitment fee, respectively. Interest on the convertible senior notes is fixed. If the interest rate on the credit facility changed by 50 basis points our interest expense would change by $6.3 million. If the amount outstanding on our credit facility changed by $10.0 million, our interest expense would change by $3.2 million.
c. Includes anticipated payments under our employee retirement health care plan through 2018 (Note 10) and our future reimbursements associated with the contractual liability covering certain of our former sulphur retiree's medical costs (Note 13).
d. These oil & gas obligations primarily reflect our net working interest share of authorized exploration and development project costs at December 31, 2007 (see below for total estimated exploration and development expenditures for 2008). Also includes escrow payments to support the funding requirements related to the acquired Newfield properties' reclamation obligations. These payments total $15 million annually, payable in quarterly installments over the next three years (twelve

payments total), and $5.0 million a year thereafter until certain requirements under the arrangement are met.

e. Amount primarily reflects leases for office space in two buildings in Houston, Texas, which terminate in April 2009 and July 2014, respectively and office space in Lafayette, Louisiana which terminates in November 2011.

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

Our exploration, development and other capital expenditures for 2008 are expected to be approximately $225 million, including $40 million of carryover costs from 2007, $95 million for development costs and $90 million for Flatrock, Blackbeard and other exploration opportunities. These expenditures may also increase as additional exploration opportunities are presented to us or to fund development costs associated with additional successful wells. We also plan to spend approximately $80 million in 2008 to abandon and remove oil and gas structures from the Gulf of Mexico, the substantial majority of which is associated with structures acquired in the Newfield transaction that were severely damaged by hurricanes in 2005. We plan to fund our exploration, development and reclamation activities with our operating cash flow and availability under our credit facility (see "— Senior Secured Revolving Credit Facility" above). 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 Item 1A. "Risk Factors" included in this Form 10-K.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Management's Discussion and Analysis of our financial condition and results of operations is based upon our consolidated financial statements, which have been prepared in conformity with 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 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 concluded. 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 became obligated for reclamation obligations related to wells and facilities located onshore Louisiana, which are subject to the laws and regulations of the State of Louisiana.

In 2007, we also assumed responsibility for future liabilities associated with the acquired Newfield properties. Among these reclamation obligations are the plugging and abandonment of wells, the reclamation and removal of platforms, facilities and pipelines, and the repair and replacement of wells, equipment and facilities, including obligations associated with damages sustained from Hurricanes Ivan, Katrina and Rita.

Our sulphur reclamation obligations are associated with our former sulphur mining operations. In June 2000 we elected to cease all sulphur mining operations, and at that time fully accrued the estimated reclamation costs associated with our Main Pass sulphur mine and related facilities and the related storage facilities at Port Sulphur, Louisiana. We had previously fully accrued all estimated costs associated with the closed Caminada and Grand Ecaille sulphur mines and related 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 (Note 9).

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 use estimates in determining our 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. To calculate the fair value of the estimated obligations, we apply an estimated long-term inflation rate of 2.5 percent and a market risk premium of 10 percent, which is 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 discount the resulting projected cash flows at our estimated credit-adjusted, risk-free interest rates for the corresponding time periods over which these costs would be incurred.

We revise our reclamation and well abandonment estimates whenever warranted by events but at a minimum at least once every year. Revisions have been made for (1) the inclusion of estimates for new properties including estimates for the properties acquired from Newfield; (2) 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 (3) 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 8.51 percent to 10.0 percent at December 31, 2007 and 9.33 percent to 10.0 percent at December 31, 2006.

The following table summarizes the estimates of our reclamation obligations at December 31, 2007 and 2006 (in thousands):

	Oil and Gas		Sulphur	
	2007	2006	2007	2006
Undiscounted cost estimates	$ 448,095	$ 41,600	$ 38,712	$ 42,244
Discounted cost estimates	$ 294,737	$ 25,175	$ 21,300	$ 23,094

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	$ 23.8	$ (21.5)	$ 4.2	$ (3.6)
Discounted	11.5	(10.9)	2.7	(2.8)
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, 2007, we estimate that our depletion, depreciation and amortization expense for 2007 would have decreased by approximately $12.7 million, while a 10 percent decrease in estimated proved reserves for each property would have resulted in an approximate $13.5 million increase in our depletion, depreciation and amortization expense for 2007. 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.

Estimate of Purchase Price Allocation. The preliminary purchase price of the Newfield property acquisition was allocated to the assets and liabilities that were acquired based on their estimated fair value at the acquisition date. The allocation of the purchase price to the Newfield properties' assets and liabilities is based on our preliminary valuation estimates. These allocations will be finalized based on valuation and other studies to be performed by us with the assistance of third party valuation specialists. As a result, the final adjusted purchase price and purchase price allocations may differ, possibly materially, from those amounts initially recorded.

Postretirement and Other Employee Benefits Costs. As discussed in Note 13, 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, 2007, an initial health care cost trend of 8.0 percent was used in 2008, with annual ratable decreases until reaching 5.0 percent in 2012. A one percentage point increase in the initial health care cost trend rate would have increased our recorded liability by $0.6 million at December 31, 2007; while a one percentage point decrease would have reduced our recorded liability by $0.5 million. We used a 8.5 percent discount at December 31, 2007 and a 7.5 percent discount rate at December 31, 2006. A one-percentage point increase in the discount rate would have decreased our net loss by approximately $0.3 million in 2007, while a one-percentage point decrease in the discount rate would have increased our net loss by approximately $0.3 million.

DISCLOSURES ABOUT MARKET RISKS

Our revenues are primarily 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 currently projected sales volumes of natural gas and oil for 2008, excluding the sales quantity amounts associated with our current oil and gas derivative contract amounts (see below), a change of $1.00 per MMbtu in the average realized price would have an approximate $75 million net impact on our revenues and pre-tax operating results and a $5 per barrel change in average oil realization would have an approximate $20 million net impact on our revenues and pre-tax operating results. Based on our currently projected sales volumes for 2008, excluding those volumes committed for sale under our existing oil and gas derivative contracts, a 10 percent fluctuation in natural gas sales volumes would impact our revenues by approximately $65 million and our pre-tax operating results by approximately $30 million while a 10 percent fluctuation in our oil sales volumes would have an approximate $35 million impact on revenues and an approximate $25 million impact on our pre-tax operating results.

Our production 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" of this Form 10-K.

As a result of indebtedness incurred in connection with the acquisition of the Newfield properties, our interest rate risk has significantly increased. Our credit facility has a variable rate which exposes us to interest rate risk. At the present time we do not hedge our exposure to fluctuations in interest rates. Based on our outstanding borrowings under the credit facility at December 31, 2007 (Note 6), a change of 100 basis points in applicable annual interest rates would have an approximate $2.7 million annual pre-tax impact on our results of operations and cash flow. Assuming our effective interest rate on our credit facility at December 31, 2007 remained constant, a change of $10.0 million in our outstanding borrowings under the credit facility would have an approximate $0.7 million annual pre-tax impact on our results of operations and cash flows.

In connection with our acquisition of the Newfield properties, we entered into various hedging contracts for a portion of our projected 2008-2010 sales of oil and natural gas (Note 7). The sensitivity of a $1.00 per MMbtu change from the average swap price for the natural gas volumes covered by the hedging contracts is $16.4 million in 2008, $7.3 million in 2009 and $2.6 million in 2010. The sensitivity of a $5.00 per barrel change in the average swap price for the oil volumes covered by the hedging contracts is $3.5 million in 2008, $1.6 million in 2009 and $0.6 million in 2010. The sensitivity of a $1.00 per MMbtu change in natural gas prices from the $6.00 per MMbtu contract put price is approximately $6.6 million in 2008, $3.2 million in 2009 and $1.2 million in 2010. The sensitivity of a $5.00 per barrel change in crude oil prices from the $50.00 per barrel contract put price is approximately $1.4 million in 2008 $0.6 million in 2009 and $0.3 million in 2010.

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

Acquisition Accounting

In December 2007, the FASB issued SFAS No. 141(R), "Applying the Acquisition Method." SFAS 141(R) requires an acquirer to recognize 100 percent of the fair values of acquired assets, with limited exceptions, even if the acquirer has not acquired 100 percent of its target. Additionally, contingent consideration arrangements and preacquisition contingencies will be measured at fair value on the acquisition date and included in the basis of the purchase price. Transaction costs will now be expensed as incurred and not considered as part of the fair value of the acquisition; however, acquired research and development will no longer be expensed at acquisition, but instead will be capitalized as an indefinite-lived intangible asset. SFAS 141(R) is effective for fiscal years beginning after December 15, 2008 and early adoption is not permitted; as a result, our accounting for the Newfield properties acquisition is not affected by this new standard. We are still reviewing the provisions of SFAS No. 141 (R) and have not determined the impact of adoption.

Noncontrolling Interests

In December 2007, the FASB issued SFAS No. 160, "Accounting for Noncontrolling Interests." SFAS 160 clarifies the classification of noncontrolling interests in the consolidated balance sheet and the accounting for and reporting of transactions between the reporting entity and holders of these noncontrolling interests. Under SFAS 160, noncontrolling interests (minority interests) are to be considered equity transactions and reflected accordingly in the balance sheet and related statement of cash flow. SFAS 160 will require separate disclosure on the face of the income statement distinguishing between the controlling and noncontrolling interests. SFAS 160 is effective for fiscal years beginning after December 15, 2008 and early adoption is not permitted. We do not believe that SFAS No. 160 will have a material impact on our financial statements.

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. The adoption of the provisions of SFAS No. 157 is not expected to have a material impact on our financial statements.

In February 2007, the FASB issued SFAS No. 159 "The Fair Value Option for Financial Assets and Liabilities." SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value. This statement is effective for fiscal years beginning after November 15, 2007, with early adoption allowed. The adoption of the provisions of SFAS No. 159 will not have an impact on our financial statements.

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" 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 significantly adversely affected by 2005 hurricane activity.

CAUTIONARY STATEMENT

Management's Discussion and Analysis of Financial Condition and Results of Operation 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 Item 1A. of 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, who audited the Company's consolidated financial statements included in this Form 10-K, has issued an attestation report on the Company's internal control over financial reporting, 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 McMoRan Exploration Co.'s internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). 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 included in the accompanying Management Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on 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, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, McMoRan Exploration Co. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, 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, 2007 and 2006, and the related consolidated statements of operations, cash flow, and changes in stockholders' equity (deficit) for each of the three years in the period ended December 31, 2007, of McMoRan Exploration Co., and our report dated March 14, 2008 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana
March 14, 2008

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, 2007 and 2006, and the related consolidated statements of operations, cash flows, and changes in stockholders' equity (deficit) for each of the three years in the period ended December 31, 2007. 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, 2007 and 2006, and the consolidated results of its operations and its cash flow for each of the three years in the period ended December 31, 2007, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), McMoRan Exploration Co.'s internal control over financial reporting as of December 31, 2007, 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 14, 2008, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana
March 14, 2008

McMoRan EXPLORATION CO.
CONSOLIDATED BALANCE SHEETS

	December 31, 2007	December 31, 2006
	(In Thousands, Except Share Related Amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 4,830	$ 17,830
Restricted investments	-	5,930
Accounts receivable	128,690	45,636
Inventories	11,507	25,034
Prepaid expenses	14,331	16,190
Fair value of oil and gas derivative contracts	16,623	-
Current assets from discontinued operations, including restricted cash of $0.5 million and $0.4 million, respectively	3,029	6,492
Total current assets	179,010	117,112
Property, plant and equipment, net	1,503,359	282,538
Sulphur business assets	349	362
Restricted investments and cash	7,036	3,288
Fair value of oil and gas derivative contracts	4,317	-
Deferred financing costs	21,217	5,377
Total assets	$ 1,715,288	$ 408,677
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)		
Current liabilities:		
Accounts payable	$ 97,821	$ 85,608
Accrued liabilities	68,292	32,740
6% convertible senior notes	100,870	-
Other short term borrowings	10,665	-
Accrued interest and dividends payable	13,055	5,479
Current portion of accrued oil and gas reclamation costs	80,839	2,604
Current portion of accrued sulphur reclamation costs	12,145	12,909
Fair value of oil and gas derivative contracts	14,001	-
Current liabilities from discontinued operations	2,624	3,678
Total current liabilities	400,312	143,018
Senior secured revolving credit facility	274,000	28,750
5¼% convertible senior notes	115,000	115,000
6% convertible senior notes	-	100,870
11.875% senior notes	300,000	-
Accrued oil and gas reclamation costs	213,898	23,272
Accrued sulphur reclamation costs	9,155	10,185
Contractual postretirement obligation	6,216	9,831
Fair value of oil and gas derivative contracts	7,516	-
Other long-term liabilities	16,962	17,151
Total liabilities	1,343,059	448,077
Commitments and contingencies		
Mandatorily redeemable convertible preferred stock, net of unamortized offering costs of $0.8 million at December 31, 2006	$ -	$ 29,043

McMoRan EXPLORATION CO.
CONSOLIDATED BALANCE SHEETS
(Continued)

	December 31,	
	2007	2006
	(In Thousands, Except Share Related Amounts)	
Stockholders' equity (deficit):		
Preferred stock, par value $0.01, 50,000,000 shares authorized, 2,587,500 shares issued and outstanding ($100 per share liquidation preference) at December 31, 2007 (Note 8)	$ 258,750	$ -
Common stock, par value $0.01, 150,000,000 shares authorized, 55,741,251 shares and 30,740,275 shares issued and outstanding, respectively	558	307
Capital in excess of par value of common stock	718,472	477,178
Accumulated deficit	(559,459)	(499,725)
Accumulated other comprehensive loss	(653)	(1,273)
Common stock held in treasury, 2,471,674 shares and 2,433,545 shares, at cost, respectively	(45,439)	(44,930)
Stockholders' equity (deficit)	372,229	(68,443)
Total liabilities, mandatorily redeemable convertible preferred stock and stockholders' equity (deficit)	$ 1,715,288	$ 408,677

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

McMoRan EXPLORATION CO.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2007	2006	2005
	(In Thousands, Except Per Share Amounts)		
Revenues:			
Oil and natural gas	$ 475,250	$ 196,717	$ 118,176
Service	5,917	13,021	11,951
Total revenues	481,167	209,738	130,127
Costs and expenses:			
Production and delivery costs	122,127	53,134	29,569
Depletion, depreciation and amortization expense	256,007	104,724	25,896
Exploration expenses	58,954	67,737	63,805
General and administrative expenses	27,973	20,727	19,551
Loss on oil and gas derivative contracts	5,181	-	-
Start-up costs for Main Pass Energy Hub™ Project	9,754	10,714	9,749
Exploration expense reimbursement (Note 3)	-	(10,979)	-
Litigation settlement, net of insurance proceeds (Note 13)	-	(446)	12,830
Insurance recoveries (Note 5)	(2,338)	(3,306)	(8,900)
Total costs and expenses	477,658	242,305	152,500
Operating income (loss)	3,509	(32,567)	(22,373)
Interest expense, net	(66,366)	(10,203)	(15,282)
Other (expense) income, net	(704)	(1,946)	6,185
Loss from continuing operations before income taxes	(63,561)	(44,716)	(31,470)
Provision for income taxes	-	-	-
Loss from continuing operations	(63,561)	(44,716)	(31,470)
Income (loss) from discontinued operations	3,827	(2,938)	(8,242)
Net loss	(59,734)	(47,654)	(39,712)
Preferred dividends and amortization of convertible preferred stock issuance costs	(4,172)	(1,615)	(1,620)
Net loss applicable to common stock	$ (63,906)	$ (49,269)	$ (41,332)
Basic and diluted net loss per share of common stock:			
Net loss from continuing operations	$(1.97)	$(1.66)	$(1.35)
Net income (loss) from discontinued operations	0.11	(0.10)	(0.33)
Net loss per share of common stock	$(1.86)	$(1.76)	$(1.68)
Average common shares outstanding:			
Basic and diluted	34,283	27,930	24,583

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

McMoRan EXPLORATION CO.
CONSOLIDATED STATEMENTS OF CASH FLOW

	Years Ended December 31,		
	2007	2006	2005
		(In Thousands)	
Cash flow from operating activities:			
Net loss	$ (59,734)	$ (47,654)	$ (39,712)
Adjustments to reconcile net loss to net cash provided by operating activities:			
(Income) loss from discontinued operations	(3,827)	2,938	8,242
Depletion, depreciation and amortization expense	256,007	104,724	25,896
Exploration drilling and related expenditures	22,832	45,591	49,621
Compensation associated with stock-based awards	13,107	15,822	1,677
Loss on induced conversion of convertible senior notes	-	4,301	-
Amortization of deferred financing costs	14,713	1,891	2,225
Loss on oil and gas derivative contracts	5,181	-	-
Reclamation expenditures	(10,622)	(670)	(4)
Purchase of oil and gas derivative contracts	(4,604)	-	-
Other	269	997	(261)
(Increase) decrease in restricted cash	(3,748)	278	3,448
(Increase) decrease in working capital:			
Accounts receivable-customers	(51,433)	(2,423)	(14,750)
Accounts receivable-joint interest partners	(10,099)	(3,364)	11,084
Accounts receivable-other	(2,228)	1,264	1,484
Accounts payable and accrued liabilities	27,195	7,743	36,469
Inventories	13,527	(17,050)	(7,127)
Prepaid expenses	12,526	(14,845)	(48)
Net cash provided by continuing operations	219,062	99,543	78,244
Net cash used in discontinued operations	(11,424)	(4,352)	(4,706)
Net cash provided by operating activities	207,638	95,191	73,538
Cash flow from investing activities:			
Exploration, development and other capital expenditures	(153,210)	(252,369)	(161,262)
Acquisition of Newfield properties, net	(1,047,936)	-	-
Property insurance reimbursement	-	3,947	3,500
Proceeds from restricted investments	6,056	16,505	15,150
Increase in restricted investments	(126)	(229)	(502)
Proceeds from sale of oil and gas properties	-	1,071	-
Net cash used in continuing activities	(1,195,216)	(231,075)	(143,114)
Net cash used in discontinued operations	-	-	(66)
Net cash used in investing activities	$ (1,195,216)	$ (231,075)	$ (143,180)

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

	Years Ended December 31,		
	2007	2006	2005
		(In Thousands)	
Cash flow from financing activities:			
Net borrowings under revolving credit facility	$ 245,250	$ 28,750	$ -
Proceeds from sale of 11.875% senior notes	300,000	-	-
Net proceeds from sale of 6¾% mandatory convertible preferred stock	250,385	-	-
Net proceeds from sale of common stock	200,189	-	-
Proceeds from bridge loan facility	800,000	-	-
Repayment of bridge loan facility	(800,000)	-	-
Proceeds from senior term loan	100,000	-	-
Repayment of senior term loan	(100,000)	-	-
Financing costs	(30,553)	(531)	-
Dividends paid on convertible preferred stock	(1,121)	(1,494)	(1,129)
Proceeds from exercise of stock warrants	9,148	-	-
Proceeds from exercise of stock options and other	1,280	389	2,363
Payments for induced conversion of convertible senior notes	-	(4,301)	-
Net cash provided by continuing operations	974,578	22,813	1,234
Net cash activity from discontinued operations	-	-	-
Net cash provided by financing activities	974,578	22,813	1,234
Net decrease in cash and cash equivalents	(13,000)	(113,071)	(68,408)
Cash and cash equivalents at beginning of year	17,830	130,901	199,309
Cash and cash equivalents at end of year	$ 4,830	$ 17,830	$ 130,901
Interest paid	$ 67,622	$ 9,382	$ 15,150
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' EQUITY (DEFICIT)

	Years Ended December 31,		
	2007	2006	2005
	(In Thousands, Except Share Amounts)		
Preferred stock:			
Balance at beginning of year	$ -	$ -	$ -
Shares sold in equity offering, representing 2,587,500 shares	258,750	-	-
Balance end of year, representing 2,587,500 shares	258,750	-	-
Common stock:			
Balance at beginning of year representing 30,740,275 shares in 2007, 27,122,538 shares in 2006 and 26,670,574 shares in 2005	307	271	267
Shares issued in equity offering representing 16,887,500 shares (at $12.40 per share) (Note 8)	169	-	-
Shares issued in debt conversion transactions representing 3,552,494 shares	-	36	-
Exercise of stock warrants representing 1,742,424 shares	17	-	-
Exercise of stock options and other representing 219,633 shares in 2007, 56,927 shares in 2006 and 302,408 shares in 2005	3	-	3
Mandatorily redeemable preferred stock conversions representing 6,205,419 shares in 2007, 8,316 shares in 2006 and 149,556 shares in 2005	62	-	1
Balance at end of year representing, 55,795,251 shares in 2007, 30,740,275 shares in 2006 and 27,122,538 shares in 2005	558	307	271
Capital in Excess of Par Value:			
Balance at beginning of year	477,178	410,139	406,458
Costs associated with preferred stock equity offering	(8,365)	-	-
Common stock equity offering, net of offering costs of $9.6 million	200,020	-	-
Shares issued in debt conversion transactions	-	52,513	-
5% mandatorily redeemable preferred stock conversions	29,786	40	719
Stock-based compensation expense	13,107	15,822	1,168
Exercise of stock warrants	9,130	-	-
Exercise of stock options	1,787	389	2,363
Shares tendered for exercise of stock options	-	-	1,051
Dividends on preferred stock and amortization of related issuance cost	(4,171)	(1,615)	(1,620)
Unamortized value of restricted stock units on adoption of new accounting standard	-	(110)	-
Balance at end of year	718,472	477,178	410,139
Unamortized value of restricted stock units:			
Balance beginning of year	-	(110)	(619)
Unamortized value of restricted stock units on adoption of new accounting standard	-	110	-
Amortization of related deferred compensation	-	-	509
Balance end of year	-	-	(110)
Accumulated Deficit:			
Balance at beginning of year	(499,725)	(452,071)	(412,359)
Net loss	(59,734)	(47,654)	(39,712)
Balance at end of year	$ (559,459)	$ (499,725)	$ (452,071)

McMoRan EXPLORATION CO.
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY (DEFICIT)
(Continued)

	Years Ended December 31,		
	2007	2006	2005
	(In Thousands, Except Share Amounts)		
Accumulated Other Comprehensive Loss:			
Balance at beginning of year	$ (1,273)	$ -	$ -
Adoption of SFAS No. 158 (Note 1)	-	(1,273)	-
Amortization of previously unrecognized pension components, net	31	-	-
Change in unrecognized net gains/losses of pension plans	589	-	-
Balance at end of year	(653)	(1,273)	-
Common Stock Held in Treasury:			
Balance at beginning of year representing, 2,433,545 shares in 2007, 2,428,121 in 2006 and 2,345,759 shares in 2005	(44,930)	(44,819)	(43,293)
Tender of 38,129 shares in 2007, 5,424 shares in 2006 and 82,362 shares in 2005 associated with the exercise of stock options and the vesting of restricted stock	(509)	(111)	(1,526)
Balance at end of year representing 2,471,674 shares in 2007, 2,433,545 shares in 2006 and 2,428,121 shares in 2005	(45,439)	(44,930)	(44,819)
Total stockholders' equity (deficit)	$ 372,229	$ (68,443)	$ (86,590)

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, are prepared in accordance with U.S. generally accepted accounting principles. The consolidated financial statements of McMoRan include the accounts of those subsidiaries where McMoRan directly or indirectly has more than 50 percent of the voting rights and for which the right to participate in significant management decisions is not shared with other shareholders. McMoRan consolidates its wholly owned McMoRan Oil & Gas LLC (MOXY) and Freeport-McMoRan Energy LLC (Freeport Energy) subsidiaries. MOXY conducts all of McMoRan's oil and gas operations while Freeport Energy is pursuing plans for a multifaceted energy services facility, including the potential development of liquefied natural gas (LNG) facilities and natural gas storage capabilities at the Main Pass Energy Hub ™ (MPEH ™) project.

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, including the presentation of restricted cash amounts within the statements of cash flow. Changes in the accounting principles applied during 2007, none of which impacted the consistency of presentation, are discussed below under the caption "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 have been separately shown for all periods presented.

On August 6, 2007, MOXY completed an acquisition of oil and gas properties with an effective date of July 1, 2007 (Note 2). McMoRan's consolidated financial statements include the results of operations of the acquired properties for the period from August 6, 2007 (closing date) to December 31, 2007. The results of operations of the acquired properties from the July 1, 2007 effective date through the closing date are reflected as a purchase price adjustment within property, plant and equipment in the accompanying consolidated balance sheet as of December 31, 2007 and as a reduction of the acquisition cost in the investing activities section of the accompanying consolidated statement of cash flow for the year ending December 31, 2007.

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 multifaceted energy services facility, including a potential 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 allocation of the purchase price for the acquired Newfield properties, 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, Note 9).

Accounts Receivable. McMoRan has no accounts receivable deemed uncollectible. The components of accounts receivable follow (in thousands):

	December 31,	
	2007	2006
Accounts receivable:		
Customers	$ 91,176	$ 19,151
Joint interest partners	33,683	24,883
Other	3,831	1,602
Total accounts receivable	$ 128,690	$ 45,636

Inventories. Product inventories totaled $1.5 million at December 31, 2007 and $1.1 million at December 31, 2006, consisting entirely of oil at Main Pass. Materials and supplies inventory totaled $10.0 million at December 31, 2007 and $23.9 million at December 31, 2006 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 weighted 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, depreciation and amortization 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 twice every year. Any such revisions are accounted for prospectively as a change in accounting estimate.

- The costs of maintenance and repairs, which are not significant improvements, are expensed when incurred.

- 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 $6.3 million in 2007, $5.3 million in 2006 and $2.1 million in 2005.

<u>Sulphur.</u> See Note 9 for results associated with its discontinued operations, which are reflected within the caption "Income (loss) from discontinued operations" in the accompanying consolidated statements of operations. McMoRan's remaining sulphur property, plant and equipment is carried at the lower of cost or estimated net realizable value.

<u>Asset Impairment.</u> 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.

In the third quarter of 2007, McMoRan's attempts to restore production from the Cane Ridge well at Louisiana State Lease 18055, located onshore in Vermilion Parish, were unsuccessful. McMoRan had no future activities planned for the well and accordingly, recorded a charge of $13.6 million to depreciation, depletion and amortization expense to write off its remaining investment in the field.

McMoRan recorded a $12.2 million charge to depletion, depreciation and amortization expense to reduce its investment in the Minuteman well at Eugene Island Block 213 to its estimated fair value at December 31, 2006 because of uncertainties as to the timing and probability of success of potential remedial operations at the well.

At December 31, 2006, limited quantities of proved reserves were assigned to the West Cameron Block 43, pending production history to support additional reserves. McMoRan monitored its investment in the West Cameron Block 43 field into 2007 as the field 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 was shut-in late February 2007. McMoRan believed that it was unlikely that proved reserves attributed to this field at December 31, 2006 would 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 value to its then estimated fair value.

Restricted investments and cash. Restricted investments and cash (excluding discontinued operations) totaled $7.0 million at December 31, 2007 and $9.2 million at December 31, 2006. The amounts includes $5.9 million classified as current at December 31, 2006. McMoRan's restricted investments at December 31, 2006 included U.S. government securities, plus accrued interest thereon, pledged as security for semi-annual interest payments made on April 6, 2007 and October 6, 2007 for McMoRan's 5¼% convertible senior notes (Note 6). McMoRan's restricted investments classified as long-term at December 31, 2007 included a $3.7 million payment, plus accrued interest thereon, held in escrow subject to an agreement associated with the reclamation liabilities of the properties acquired from Newfield (Note 13). Long-term restricted cash also included $3.2 million of escrowed funds at December 31, 2007 and 2006 for certain assumed environmental liabilities (Note 13). McMoRan has $0.5 million of restricted cash associated with its discontinued sulphur operations (Note 9).

Revenue Recognition. McMoRan generally sells crude oil and natural gas under short-term agreements at prevailing market prices. Revenue for the sale of crude oil and natural gas is recognized when title passes to the customer, when prices are fixed or determinable and collection is reasonable assured. 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 working interests. When McMoRan receives a volume in excess of its net working interests, it records a liability and under deliveries are recorded as receivables. At December 31, 2007, McMoRan had natural gas imbalance receivables of $3.3 million, including $3.2 million associated with the properties acquired from Newfield (Note 2). At December 31, 2007, the liability associated with McMoRan's over deliveries totaled $3.2 million, including $2.5 million for the acquired properties. McMoRan recorded a liability of $2.6 million for the values associated with the estimated net overdelivered position for the acquired properties at August 6, 2007, which is reflected as a component of the net purchase price (Note 2). The volume and values associated with McMoRan's gas imbalances were immaterial at December 31, 2006.

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 three year period ended December 31, 2007, McMoRan recognized $3.7 million in 2007, $1.9 million in 2006 and $4.7 million in 2005 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, 2007, 2006 or 2005. McMoRan recognizes oil and gas revenues from production on properties eligible for royalty relief as the amounts are earned. If the price threshold is exceeded during a given period, 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 3), 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 individual customers representing 10 percent or more of its total consolidated oil and gas revenues in each of the three years in the period ended December 31, 2007 is as follows:

	Year Ended December 31,		
	2007	2006	2005
A	27%	20%	14%
B	24	-	-
C	13	-	-
D	<10	26	27
E	<10	25	<10
F	<10	16	<10
G	-	-	27
H	<10	-	15

All of McMoRan's customers are located in the United States. McMoRan does not believe the loss of any of these purchasers would have a material adverse affect on its operations because oil and gas is a commodity in demand and alternative purchasers, if needed, are available.

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 uses estimates derived from information provided by third party specialists in determining its estimated asset retirement obligations under multiple probability-assessed 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 (Note 13).

Accumulated Other Comprehensive Income (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 other comprehensive income (loss) items until it adopted SFAS No. 158 "Accounting for Defined Benefit and Other Postretirement Plans" on December 31, 2006 (Note 10). McMoRan's accumulated other comprehensive loss for 2007, 2006 and 2005 follows (in thousands):

	2007	2006	2005
Net loss	$ (59,734)	$ (47,654)	$ (39,712)
Other comprehensive income (loss)			
Amortization of previously unrecognized pension components, net	31	-	-
Change in unrecognized net gains/losses of pension plans	589	-	-
Accumulated other comprehensive loss	$ (59,114)	$ (47,654)	$ (39,712)

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 may account for its future 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.

In connection with the closing of the Newfield transaction and the related financings, MOXY entered into oil and gas derivative contracts for a portion of its anticipated production for the years 2008 through 2010. The oil and gas derivative contracts were not designated as hedges for accounting purposes. Accordingly, these contracts are subject to mark-to-market fair value adjustments, the impact of which is recognized immediately in McMoRan's operating results. McMoRan records all gains and losses associated with its derivative contracts within a separate line in the accompanying consolidated statements of operations, and any related cash flow effect is recorded within cash flows from operations within the related consolidated statements of cash flow. McMoRan believes the operating presentation of its oil and gas derivatives contracts is appropriate in both its statements of operations and cash flow because the sale of oil and natural gas production represents the primary source of its operating income and cash flow. See Note 7 for information regarding McMoRan's oil and gas derivative contracts.

Restricted Stock Units. Under McMoRan's stock-based compensation plans (Note 10), its Board of Directors granted 43,000 RSUs in 2007. There were no RSUs granted in 2006 or 2005. 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. RSUs converted into common stock totaled 4,167 shares in 2007 and 29,165 shares in 2006. Upon issuance of the RSUs, unearned compensation equivalent to the market value at the date of grants is recorded as deferred compensation in stockholders' equity (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 2007, $0.1 million in 2006 and $0.5 million in 2005.

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 December 31, 2007. 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, 6¾% mandatorily 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 reduced the reported net loss per share for these periods. The excluded common share amounts are summarized below (in thousands):

	Years Ended December 31,		
	2007	2006	2005
In-the-money stock options [a, b]	1,727	1,097	1,336
Shares issuable upon exercise of stock warrants [a, c]	1,467	1,753	1,800
Shares issuable upon assumed conversion of 5% mandatorily redeemable preferred stock [d]	3,103	6,205	6,214
Shares issuable upon assumed conversion of 6¾% mandatorily convertible preferred stock [e]	2,525	-	-
Shares issuable upon assumed conversion of 6% convertible senior notes [f]	7,079	7,079	9,123
Shares issuable upon assumed conversion of 5¼% convertible senior notes [g]	6,938	6,938	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). On December 12, 2007, the stock warrant for 1.74 million common shares was exercised and the shares included in this calculation represent the 348 days the warrants were outstanding in 2007. The remaining warrants, which expire in September 2008, are exercisable for McMoRan common stock at any time at an exercise price of $5.25 per share (Note 5).
d. Amount represents total equivalent common stock shares assuming conversion of 5% mandatorily redeemable preferred stock (Note 8). The remaining shares of the 5% preferred stock were converted into common stock at June 30, 2007. The amount is reduced from 6.2 million equivalent shares that were issued upon conversion to reflect the six months the preferred stock was outstanding. Preferred dividends and related costs totaled $1.6 million in 2007, 2006 and 2005.
e. Amount represents total equivalent common stock shares assuming conversion of 6¾% mandatorily convertible preferred stock (Note 8). The amount is reduced from the total 17.4 million equivalent shares that would have been issued upon conversion to reflect the 53 days the preferred stock was outstanding in 2007. Preferred dividends and related costs totaled $2.6 million in 2007.
f. Amount represents total equivalent common stock shares assuming conversion of 6% convertible senior notes (Note 6). Related net interest expense totaled $6.6 million in 2007, $4.7 million in 2006 and $8.1 million in 2005.
g. Amount represents total equivalent common stock shares assuming conversion of 5¼% convertible senior notes (Note 6). Net interest expense on the 5¼% convertible senior notes totaled $6.1 million in 2007, $4.2 million in 2006 and $7.2 million in 2005.

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 (Note 10). 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 2007 and 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 because the grantee has earned that one year vesting benefit under the terms of McMoRan's stock options plans due to length of tenured service. 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.

McMoRan currently recognizes no income tax benefits for deductions resulting from the exercise of stock options because all of its net deferred tax assets, including significant net operating loss carryforwards, have been reserved with a full valuation allowance (Note 11).

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

	Year Ended December 31,		
	2007	2006	2005
Cost of options awarded to employees (including Directors)	$ 12,415[a]	$ 15,129[a]	$ 858[b]
Cost of options awarded to non-employees and Advisory Directors	630	588	310
Cost of restricted stock units	62	105	509
Total stock-based compensation cost	$ 13,107	$ 15,822	$ 1,677

a. Includes $2.8 million and $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 2007 and 2006, respectively. Also includes $1.2 million and $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) during 2007 and 2006, respectively.

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 10). 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.

A summary of stock-based compensation by financial statement line item for the three years in the period ended December 31, 2007 is as follows (in thousands):

	2007	2006	2005
General and administrative expenses	$ 6,334	$ 7,120	$ 615
Exploration expenses	6,296	8,104	1,052
Main Pass Energy Hub start-up costs	477	598	10
Total stock-based compensation cost	$ 13,107	$ 15,822	$ 1,677

As of December 31, 2007, McMoRan has eight stock-based employee and director compensation plans, which are described in Note 10. 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's common stock. McMoRan uses historical data to estimate option exercise, forfeitures and expected life of the options. 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 is currently not permitted to pay, cash dividends on its common stock. The assumptions used to value stock option awards during the years ended December 31, 2007 and 2006 are noted in the following table:

	2007	2006
Fair value (per share) of stock option on grant date	$ 6.94[a]	$ 11.85[b]
Expected and weighted average volatility	52.23%	55.5%
Expected life of options (in years)	6.29[a]	7[b]
Risk-free interest rate	4.76%	4.5%

a. Excludes stock options that were granted with immediate vesting (445,000 shares, including 400,000 shares granted to the Co-Chairmen in lieu of cash compensation for 2007) with an expected life of 6.56 years and fair value of stock options on grant date of $7.02 per share.
b. Excludes stock options that were granted with immediate vesting (500,000 shares granted to the Co-Chairmen in lieu of any cash compensation for 2006) with an expected life of six years and a grant date fair value of $11.52 per share.

As of December 31, 2007, McMoRan had approximately $10.1 million of total unrecognized compensation costs related to unvested stock options, which is expected to be recognized over a weighted average period of approximately one year.

The following table illustrates the effect on McMoRan's net loss and net loss per share for the year ended December 31, 2005, 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
Basic net loss applicable to common stock, as reported	$ (41,332)
Add: Stock-based employee compensation expense recorded in net loss for restricted stock units and employee stock options	1,367
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards	(11,439)
Pro forma diluted net loss applicable to common stock	$ (51,404)
Net loss per share:	
Basic and diluted – as reported	$ (1.68)
Basic and diluted – pro forma	$ (2.09)

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 the requirements of SFAS 123 issued during the year ended December 31, 2005.

Fair value (per share) of stock options	$ 11.45
Risk free interest rate	4.5%
Expected volatility rate	61%
Expected life of options (in years)	7
Assumed annual dividend	-

New Accounting Standards. Effective January 1, 2007, McMoRan adopted Financial Accounting Standards Board (FASB) 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. The adoption of FIN 48 had no effect on McMoRan's financial statements. See Note 11 for additional disclosure regarding McMoRan's income taxes.

In December 2007, the FASB issued SFAS No. 141(R), "Applying the Acquisition Method." SFAS 141(R) requires an acquirer to recognize 100 percent of the fair values of acquired assets, with limited exceptions, even if the acquirer has not acquired 100 percent of its target. Additionally, contingent consideration arrangements and preacquisition contingencies will be measured at fair value on the acquisition date and included in the basis of the purchase price. Transaction costs will now be expensed as incurred and not considered as part of the fair value of the acquisition; however, acquired research and development will no longer be expensed at acquisition, but instead will be capitalized as an indefinite-lived intangible asset. SFAS 141(R) is effective for fiscal years beginning after December 15, 2008 and early adoption is not allowed; as a result, McMoRan's accounting for the Newfield properties acquisition is not affected by this new standard.

In December 2007, the FASB issued SFAS No. 160, "Accounting for Noncontrolling Interests." SFAS 160 clarifies the classification of noncontrolling interests in the consolidated balance sheet and the accounting for and reporting of transactions between the reporting entity and holders of these noncontrolling interests. Under SFAS 160, noncontrolling interests (minority interests) are to be considered equity transactions and reflected accordingly in the balance sheet and related statement of cash flow. SFAS 160 will require separate disclosure on the face of the income statement distinguishing between the controlling and noncontrolling interests. SFAS 160 is effective for fiscal years beginning after December 15, 2008 and early adoption is not permitted. McMoRan does not believe that SFAS No. 160 will have a material impact on its financial statements.

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. The adoption of the provisions of SFAS No. 157 is not expected to have a material impact on McMoRan's financial statements.

In February 2007, the FASB issued SFAS No. 159 "The Fair Value Option for Financial Assets and Liabilities." SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value. This statement is effective for fiscal years beginning after November 15, 2007, with early adoption allowed. The adoption of the provisions of SFAS No. 159 will not have an impact on McMoRan's financial statements.

2. ACQUISITION OF GULF OF MEXICO SHELF PROPERTIES

On August 6, 2007, MOXY completed the acquisition of substantially all of the proved oil and gas property interests and related assets of Newfield Exploration Company (Newfield) located on the outer continental shelf of the Gulf of Mexico for total cash consideration of $1.1 billion and assumption of the related reclamation obligations. McMoRan also acquired 50 percent of Newfield's interests in unproved exploration leases on the outer continental shelf of the Gulf of Mexico and a majority of Newfield's interests in the inventory of leases associated with the Treasure Island and Treasure Bay ultra deep prospects. McMoRan funded the acquisition by borrowing $800 million under an unsecured bridge loan facility and $394 million under a senior secured revolving credit facility (Note 6).

At December 31, 2007, the purchase price reflects a reduction of $35.6 million to reflect the net cash flow of the acquired properties' operations for the period from the July 1, 2007 effective date to August 6, 2007 (Note 1). The allocation of the purchase price to the acquired assets and assumed liabilities is based on McMoRan's preliminary valuation estimates. Although these allocations are not final, McMoRan does not believe there will be material changes to these amounts. The following table summarizes the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition (August 6, 2007) (in thousands):

Cash paid for acquired assets at closing (August 6, 2007)	$ 1,076,286
Estimated oil & gas reclamation costs	267,537
Net assets acquired at closing	1,343,823
Post closing adjustments	(35,649)[a]
Other acquisition related costs	13,416
Net assets acquired	$ 1,321,590

a. Represents net cash flow from the operation of the acquired properties during the period from July 1, 2007 (effective date) to August 6, 2007 (closing date).

The allocation of the purchase price of the acquired properties at the date of acquisition follows:

Accounts receivable	$ 35,649
Oil and gas property, plant and equipment	1,321,590
Asset retirement obligations	(267,537)
Other accrued liabilities	(13,416)
Cash paid for acquired assets at closing (August 6, 2007)	$ 1,076,286

The following unaudited pro forma financial information assumes MOXY acquired the properties from Newfield effective January 1, 2007 and 2006, respectively, for the periods presented (amounts in thousands, except for per share data).

	(Pro Forma, Unaudited) Years Ended December 31,	
	2007	2006
Revenues	$ 888,550	$ 822,791
Operating income	85,163	196,619
Net income (loss)	(55,645)	55,761
Basic net income (loss) per share of common stock	$(1.62)	$2.00
Diluted net income (loss) per share of common stock	(1.62)	1.23

3. 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 outer 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 (Unaudited)

As of December 31, 2007, McMoRan owned or controlled interests in 603 oil and gas leases in the Gulf of Mexico and onshore Louisiana and Texas covering 1.52 million gross acres (0.64 million acres net to McMoRan's interests). McMoRan's acreage position on the outer continental shelf includes 1.30 million gross acres (0.57 million acres net to McMoRan's interests). McMoRan owns leasehold interests to approximately 0.5 million gross acres, 0.1 million net to McMoRan's interests, that are scheduled to expire in 2008. McMoRan holds potential reversionary interests in oil and gas leases that it has farmed-out or sold to other oil and gas exploration companies but that will partially revert to McMoRan upon the achievement of specified production quantity thresholds or the achievement of specified net production proceeds.

The following table shows the oil and gas acreage in which McMoRan held interests as of December 31, 2007. The table does not account for McMoRan's gross acres associated with its farm-in, or certain other farm-out arrangements (approximately 0.10 million gross acres).

	(Unaudited)			
	Developed		Undeveloped	
	Gross Acres	Net Acres	Gross Acres	Net Acres
Offshore (federal waters)	709,391	412,034	593,435	162,641
Onshore Louisiana and Texas	36,769	18,255	71,898	30,523
Total at December 31, 2007	746,160	430,289	665,333	193,164

Exploration Funding Arrangements
McMoRan intends to maintain its aggressive exploration drilling and development activities during 2008. McMoRan plans to fund these activities with its operating cash flow and borrowings under its senior secured revolving credit facility (Note 6). In addition, when feasible and appropriate, McMoRan may diversify its exploration efforts through arrangements with third parties, similar to the arrangements further discussed below.

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) pursuant to which Plains obtained the right to participate in various exploration prospects in limited areas being explored by McMoRan. None of the properties that McMoRan acquired from Newfield are subject to the agreement with Plains. As of December 31, 2007, Plains has participated in six prospects under the terms of this exploration agreement. Under the terms of the agreement, Plains paid McMoRan $20 million for 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 for prospects covered by this arrangement and is included within investing activities in the accompanying consolidated statement of cash flow.

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 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 participated in 40 percent of McMoRan's interests. McMoRan and the private partner continued to participate jointly in the exploration venture's 14 discoveries as well as the wells not fully evaluated. Service revenues related to the exploration venture totaled $9.0 million in 2006 and $7.0 million in 2005. McMoRan received no management fees for exploration venture services during 2007. McMoRan paid its exploration partner $8.0 million in the fourth quarter of 2006 for relinquishing its exploration rights to certain prospects in connection with McMoRan's entry into a new exploration agreement with Plains (see above).

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 (unaudited) surrounding the JB Mountain and Mound Point Offset wells. There are three producing wells under this farm-out program which averaged an aggregate gross rate of approximately 26 MMcef/d (unaudited) during 2007. McMoRan does not expect payout under the 100 Bcfe arrangement will occur in 2008.

4. 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 a multifaceted energy facility, including the potential development of a facility to receive and process LNG and store and distribute natural gas, could be developed at Main Pass 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™).

Following an extensive review, the Maritime Administration (MARAD) approved Freeport Energy's license application for the MPEH™ project in January 2007. MARAD concluded in its Record of Decision that construction and operations of the 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 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 commercial feasibility is established, at which point Freeport Energy may begin to capitalize certain subsequent expenditures related to the development of the project. Freeport Energy incurred start-up costs for the MPEH™ project totaling $9.8 million in 2007, $10.7 million in 2006 and $9.7 million in 2005.

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 5 and 13). Future financing and commercial arrangements could also reduce Freeport Energy's equity interest in the project.

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

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

	December 31, 2007	December 31, 2006
Oil and gas property, plant and equipment	$ 1,984,328	$ 521,372
Other	31	31
	1,984,359	521,403
Accumulated depletion, depreciation and amortization	(481,000)	(238,865)
Property, plant and equipment, net	$ 1,503,359	$ 282,538

See Note 2 regarding the acquisition of the Newfield properties which significantly increased McMoRan's investment in oil and gas property, plant and equipment in 2007.

McMoRan is planning additional development of the Blueberry Hill well at Louisiana State Lease 340. Information obtained from the Blueberry Hill well will be incorporated into the plan to further evaluate the JB Mountain Deep well at South Marsh Island Block 224. At December 31, 2007, McMoRan's investments in the Blueberry Hill and JB Mountain Deep prospects totaled $22.9 million and $29.6 million, respectively (Note 14).

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. 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 9). 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.

K1 USA also 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 received stock warrants to acquire a total of 2.5 million shares of McMoRan common stock at $5.25 per share. K1 exercised one warrant for 1.74 million shares in December 2007 for a cash price of $9.1 million. The remaining warrant for 0.76 million common shares expires in September 2008.

While the Main Pass structures did not incur significant damage from Hurricane Ivan in September 2004, 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. Capitalized costs associated with the modification of these storage facilities totaled $8.2 million. 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, $7.5 million for reimbursement of costs related to modifications of the Main Pass facilities and $0.6 million for reimbursements of other related expenditures.

While Main Pass facilities and platforms did not suffer significant damage from Hurricane Katrina in August 2005, oil operations were temporarily shut-in to perform required repairs resulting from the storm. Main Pass resumed oil production in late November 2005. Repair costs totaling $8.1 million were incurred to repair hurricane damages, primarily related to an ancillary structure. These costs were charged to expense; however such costs were partially offset by insurance reimbursements totaling $3.9 million under McMoRan's Hurricane Katrina insurance claims.

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. 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, 2007	December 31, 2006
Employee postretirement medical liability (Note 10)	$ 5,303	$ 5,668
Accrued workers compensation and group insurance	2,325	2,242
Sulphur-related environmental liability (Note 13)	3,161	3,161
Defined benefit pension plan liability (Note 10)	2,255	2,141
Nonqualified pension plan liability	1,199	1,012
Deferred compensation and other	-	208
Liability for management services (Note 13)	2,719	2,719
	$ 16,962	$ 17,151

McMoRan defers its financing costs associated with its debt instruments and amortizes the cost over the term of the related instrument. The components of deferred financing costs follow (in thousands):

	December 31, 2007			December 31, 2006		
	Gross Carrying Amount	Accumulated Amortization	Net	Gross Carrying Amount	Accumulated Amortization	Net
11.875% Senior Notes (due November 2014)	$ 8,055	$ (150)	$ 7,905	$ -	$ -	$ -
Revolving Credit Facility (Matures August 2012)	11,136	(893)	10,243	640	(94)	546
6% Convertible Senior Notes (due July 2008)	5,706	(5,160)	546	5,706	(4,068)	1,638
5¼% Convertible Senior Notes (due October 2011)	7,032	(4,509)	2,523	7,032	(3,839)	3,193
	$ 31,929	$ (10,712)	$ 21,217	$ 13,378	$ (8,001)	$ 5,377

For discussion of long-term restricted investments and cash, see Note 1.

6. LONG-TERM DEBT

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

	December 31, 2007	December 31, 2006
Senior secured revolving credit facility	$ 274,000	$ 28,750
11.875% senior notes	300,000	-
5¼% convertible senior notes	115,000	115,000
6% convertible senior notes	100,870	100,870
Other	10,665	-
Total debt	800,535	244,620
Less current maturities	(111,535)	-
Long-term debt	$ 689,000	$ 244,620

Senior Secured Revolving Credit Facility

In April 2006, McMoRan established a new four-year, $100 million Senior Secured Revolving Credit Facility (credit facility) with a group of banks for use in MOXY's oil and natural gas operations. In August 2007, the credit facility was amended and expanded in conjunction with the acquisition of oil and gas properties from Newfield. The borrowing base on the expanded credit facility was initially set at $700 million, is secured by substantially all of MOXY's oil and gas properties and matures on August 6, 2012.

Availability under the credit facility includes a borrowing base provision that is subject to redetermination by the lenders semi-annually on April 1 and October 1 of each year. The facility is also subject to a $60 million per quarter reduction in the committed availability beginning in the fourth quarter of 2007 and continuing through the fourth quarter of 2008, totaling $300 million in the aggregate. At December 31, 2007, McMoRan had borrowings of $274.0 million and $100 million in letters of credit issued under the facility. The letters of credit support the reclamation obligations assumed for the acquired Newfield properties. At December 31, 2007, McMoRan's availability for additional borrowings under the facility totaled $266.0 million.

Interest on the facility currently accrues at LIBOR plus 1.75 percent, subject to increases or decreases based on usage as a percentage of the borrowing base. Fees associated with the letters of credit and the unused commitment fee are also subject to increases or decreases based on usage as a percentage of the borrowing base. The facility contains covenants and other restrictions customary for oil and gas borrowing base credit facilities. McMoRan is in compliance with these covenants at December 31, 2007. The average interest rate on borrowings under the facility was 7.5 percent in 2007 and 8.2 percent in 2006. Interest expense on the credit facility totaled $13.3 million including $2.2 million of commitment fees and amortization of related deferred financing costs for the year ended December 31, 2007. For the year ended December 31, 2006, interest expense on the credit facility totaled $1.7 million including $0.8 million of commitment and amortization of related deferred financing costs.

At December 31, 2007, the carrying value of the credit facility approximated fair value because the interest rate is variable and is reflective of market rates.

Unsecured Bridge Loan Facility
On August 6, 2007, McMoRan entered into an $800 million interim bridge loan facility (bridge loan) in conjunction with the acquisition of the Newfield properties. McMoRan borrowed $800 million to partially fund the acquisition costs for the Newfield properties. In November 2007, McMoRan used the net proceeds from concurrent public offerings of shares of its common and 6¾% preferred stock (Note 8), the sale of the 11.875% Senior Notes due 2014 (see "11.875% Senior Notes" below) and additional borrowings under the credit facility to repay and terminate the bridge loan. Upon repayment and termination of the bridge loan, the remaining unamortized deferred financing costs associated with the bridge loan, totaling $17.9 million, were charged to interest expense. This charge was partially offset by a $9.0 million reimbursement from McMoRan's lenders of previously paid closing fees that were contractually reimbursable to McMoRan for retiring the bridge loan within 120 days of its origination. The average interest rate on borrowings under the bridge loan was 10.2 percent in 2007. For the year ended December 31, 2007, interest expense on the bridge loan totaled $30.7 million, including $9.3 million of amortization and subsequent net write off of the related deferred financing costs.

Senior Term Loan
Effective January 19, 2007, MOXY entered into a senior term loan agreement (term loan). The term loan agreement provided 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 then outstanding under the revolving credit facility.

At the closing of the acquisition of the Newfield properties, MOXY repaid and terminated the term loan by repaying the principal plus a 3.0 percent ($3.0 million) prepayment premium. The prepayment premium was charged to non-operating expense in the consolidated statement of operations. The remaining unamortized deferred financings costs associated with the term loan, totaling $2.0 million, were charged to interest expense upon the repayment and termination of the term loan. The average interest rate on borrowings under the term loan was 12.7 percent in 2007. Interest expense on the term loan during 2007 totaled $9.3 million, including amortization and subsequent write off of related deferred financing costs of $2.3 million.

11.875% Senior Notes
On November 14, 2007, McMoRan completed the sale of $300 million of 11.875% senior notes (senior notes). Net proceeds from the sale of the senior notes of approximately $292 million were used, along with additional borrowings under the credit facility, to repay remaining amounts outstanding on the bridge loan after application of the net proceeds from the concurrent public offerings of shares of McMoRan's common stock and 6¾% mandatory convertible preferred stock (Note 8). The senior notes are due on

November 15, 2014 and are unconditionally guaranteed on a senior basis by MOXY and its subsidiaries (Note 15). McMoRan may redeem some or all of these notes at its option at make-whole prices prior to November 15, 2011, and thereafter at stated redemption prices. The indenture governing the senior notes contains restrictions, including restrictions on incurring debt, creating liens, selling assets and entering into certain transactions with affiliates. The covenants also prohibit McMoRan's ability to pay certain cash dividends on common stock, repurchase or redeem common or preferred equity, prepay subordinated debt and make certain investments. Interest expense on the senior notes during 2007 totaled $4.8 million, including amortization of related deferred financing costs of $0.2 million. At December 31, 2007, the fair value of the 11.875% senior notes was approximately $300 million.

5¼% Convertible Senior Notes
On October 6, 2004, McMoRan 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. Interest expense totaled $6.7 million, $6.4 million and $8.2 million for the years ended December 31, 2007, 2006 and 2005, respectively, including amortization of deferred financing costs of $0.7 million in 2007, $0.2 million in 2006 and $0.8 million in 2005. 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. 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. The fair value of the notes was $125.4 million at December 31, 2007 and $123.9 million at December 31, 2006.

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. Interest expense totaled $7.2 million for the years ended December 31, 2007 and 2006 and $9.2 million in 2005. Amortization of the related deferred financing costs totaled $1.1 million in 2007, $1.0 million in 2006 and $1.4 million in 2005. 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. At March 13, 2008, the remaining balance for McMoRan's 6% convertible senior notes totaled $76.4 million (see "Debt Conversion Transactions"). The fair value of the notes was $109.2 million at December 31, 2007 and $119.9 million at December 31, 2006.

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 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.

Subsequent to December 31, 2007 and through March 14, 2008, through a series of privately negotiated transactions, an aggregate of $24.5 million of McMoRan's 6% convertible notes were converted into approximately 1.72 million shares of its common stock. In connection with these transactions, McMoRan paid an aggregate $0.7 million to induce the conversions. These payments will be reflected as non-operating expense in McMoRan's first quarter 2008 statement of operations.

These conversion transactions will reduce McMoRan's interest expense by $0.7 million during the first half of 2008.

7. DERIVATIVE CONTRACTS

In connection with the closing of the Newfield transaction and related financing, MOXY entered into derivative contracts for a portion of the anticipated production from its proved developed producing oil and gas properties at the time of the acquisition of the Newfield properties for the years 2008 through 2010 as follows:

	Natural Gas Positions (million MMbtu)						
	Open Swap Positions [a]			Put Options [b]			
	Annual Volumes		Average Swap Price [c]	Annual Volumes		Average Floor [c]	Total Volumes
2008	16.4	$	8.60	6.6	$	6.00	23.0
2009	7.3	$	8.97	3.2	$	6.00	10.5
2010	2.6	$	8.63	1.2	$	6.00	3.8

	Oil Positions (thousand bbls)						
	Open Swap Positions [a]			Put Options [b]			
	Annual Volumes		Average Swap Price [d]	Annual Volumes		Average Floor [d]	Total Volumes
2008	693	$	73.50	288	$	50.00	981
2009	322	$	71.82	125	$	50.00	447
2010	118	$	70.89	50	$	50.00	168

a. Covering periods January-June and November-December of the respective years.
b. Covering periods July-October of the respective years.
c. Price per MMbtu of natural gas.
d. Price per barrel of oil.

These oil and gas derivative contracts were not designated as hedges for accounting purposes. Accordingly, these contracts are subject to mark-to-market fair value adjustments, the impact of which is recognized immediately in McMoRan's operating results. For the year ended December 31, 2007, McMoRan had no realized gains or losses on its derivative contracts because settlement of its derivative contracts did not commence until January 2008. For the two month period ended February 29, 2008, McMoRan recorded losses totaling $37.4 million related to its oil and gas derivative contracts. McMoRan's unrealized (gain)/loss on these contract positions follow (in thousands):

	Years Ended December 31,		
	2007	2006	2005
Gas puts	$ 1,433	$ -	$ -
Oil puts	630	-	-
Gas swaps	(17,665)	-	-
Oil swaps	20,783	-	-
Loss on oil and gas derivative contracts	$ 5,181	$ -	$ -

The original cost of the put options was $4.6 million. There was no cost for entering into the swap contracts. At December 31, 2007, the fair value of the derivative contracts was as follows (in thousands):

	Puts		Swaps		
	Gas	Oil	Gas	Oil	Total
Current assets	$ 1,350	$ 4	$ 15,269	$ -	$ 16,623
Other assets	1,105	81	3,131	-	4,317
Current liabilities	-	-	-	(14,001)	(14,001)
Other long-term liabilities	-	-	(735)	(6,781)	(7,516)
Fair value of contracts	$ 2,455	$ 85	$ 17,665	$ (20,782)	$ (577)

8. COMMON AND MANDATORILY REDEEMABLE PREFERRED STOCK OFFERINGS

On November 7, 2007, McMoRan completed a public offering of 16.89 million shares of common stock at $12.40 per share and a concurrent public offering of 2.59 million shares of 6¾% mandatory convertible preferred stock with an offering price of $100 per share. The net proceeds from these offerings, after deducting the underwriters' discounts, were approximately $450 million. The net proceeds from these offerings were used to repay a portion of the $800 million bridge loan (Note 6) that McMoRan used to partially fund its acquisition of the Newfield properties (Note 2).

The preferred stock is recorded at liquidation preference value ($100 per share) on the accompanying consolidated balance sheet. The quarterly cash dividend rate is $1.6785 per share, with the exception of the first dividend payment which was paid at $1.8375 per share, on February 15, 2008. The 6¾% preferred stock is convertible into between 17.4 million and 20.9 million shares of McMoRan common stock, subject to certain anti-dilution adjustments, depending on the price of McMoRan's common stock. The 6¾% preferred stock will automatically convert on November 15, 2010. Holders may elect at any time before November 15, 2010 to convert at a conversion rate equal to 6.7204 shares of common stock for each share of 6¾% 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. Each share provided for a quarterly cash dividend of $0.3125 per share ($1.25 per share annually) and was 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. Through December 31, 2006, a total of 30,375 shares of the 5% convertible stock was tendered and converted into a total of approximately 0.1 million shares of McMoRan common stock. During 2007, McMoRan called for the redemption of the remaining shares of 5% preferred stock outstanding; however, the holders of the shares elected to convert them into approximately 6.2 million shares of common stock prior to the effective redemption date. McMoRan's dividend and amortization of convertible preferred stock issuance costs related to the 5% convertible preferred stock was $1.6 million for each of the three years ended December 31, 2007. Dividends paid were $1.1 million, $1.5 million and $1.1 million for the years ended December 31, 2007, 2006 and 2005, respectively. Accumulated amortization of the convertible preferred stock issuance costs totaled $0.6 million at December 31, 2006.

9. DISCONTINUED OPERATIONS

In November 1998, McMoRan acquired 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 Energy was also engaged in the mining of sulphur. In June 2002, Freeport Energy 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 "Income (loss) from discontinued operations."

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

	Years Ended December 31,		
	2007	2006	2005
Sulphur retiree costs [a]	(3,155)	(1,436)	(2,513)
Caretaking costs	901	1,889	1,476
Accretion expense – sulphur reclamation obligations	1,738	4,417 [b]	7,205 [b]
Insurance	463	881	1,030
General and administrative, legal and other	174	176	583
Other	(3,948) [c]	(2,989) [d]	461
(Income) loss from discontinued operations	$ (3,827)	2,938	8,242

a. Reflects postretirement benefit costs associated with certain retired former sulphur employees (Note 13). The amount during 2007 reflects a $4.6 million reduction in the contractual liability resulting from decreased health care claim costs. The amount during 2006 reflects a $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 program.

b. 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 increase incorporated the planned acceleration of certain of these closure costs as well as higher costs associated with a portion of the facilities. In 2005, $6.5 million was charged to expense to reflect modification of our then existing reclamation plan for Port Sulphur.
c. Includes $4.2 million of finalized insurance recoveries associated with the Port Sulphur property damage claims resulting from the 2005 hurricanes.
d. 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.

Exit From Sulphur Business
In connection with the June 2002 sale of assets, McMoRan also agreed to be responsible for certain related historical environmental obligations 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, 2007, McMoRan has paid approximately $0.2 million to settle certain claims associated with these assumed historical environmental obligations (Note 13).

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 a turnkey contract with Offshore Specialty Fabricators Inc. (OSFI) to dismantle and remove the remaining Main Pass sulphur facilities. OSFI commenced its reclamation work at the facilities not essential to any future business activities at Main Pass in 2002, which is now substantially complete. McMoRan paid OSFI $13 million for the removal of these structures at Main Pass. See Note 13 regarding the settlement of litigation between McMoRan and OSFI.

10. EMPLOYEE BENEFITS

Stock-Based Awards. At December 31, 2007, 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, 2007
2005 Stock Incentive Plan ("the 2005 Plan")	3,500,000	14,000
2004 Director Compensation Plan ("2004 Directors Plan")	175,000	114,386
2003 Stock Incentive Plan ("the 2003 Plan")	2,000,000	-
2001 Stock Incentive Plan ("the 2001 Plan")	1,250,000	-
2000 Stock Option Plan ("the 2000 Plan")	600,000	1,500
1998 Stock Option Plan ("the 1998 Plan")	775,000	10,875
1998 Stock Option Plan for Non Employee Directors (the Directors Plan")	75,000	1,000
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, 2007. A summary of stock options outstanding follows:

	2007		2006		2005	
	Number of Options	Average Option Price	Number of Options	Average Option Price	Number of Options	Average Option Price
Beginning of year	7,095,991	$15.50	5,845,416	$14.57	4,820,860	$13.97
Granted	1,353,250	12.29	1,365,500	19.79	1,310,500	16.74
Exercised	(213,695)	8.37	(26,823)	14.52	(255,699)	13.32
Expired/forfeited	(481,446)	18.33	(88,102)	20.71	(30,245)	22.25
End of year	7,754,100	14.96	7,095,991	15.50	5,845,416	14.57
Exercisable at end of year	5,636,100		5,169,822		4,167,393	

The total intrinsic value of options exercised during the years ended December 31, 2007 and 2006 was $1.0 million and less than $0.1 million, respectively. The total intrinsic value of all McMoRan's options outstanding at December 31, 2007 was $24.2 million which have a weighted average life of 7.1 years. The total intrinsic value of exercisable options totaled $13.5 million at December 31, 2007. The exercisable options had a weighted average life of 5.9 years.

The Co-Chairmen of McMoRan's Board of Directors agreed to forgo all cash compensation during each of the three years ended December 31, 2007. 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 400,000 options at an exercise price of $12.23 per share in January 2007, 500,000 options at an exercise price of $19.85 per share in January 2006 and 500,000 options at an exercise price of $16.65 per share in January 2005. The Co-Chairmen also received additional grants totaling 400,000 stock options in January 2007, 350,000 stock options in January 2006 and 350,000 stock options in January 2005, all of which vest ratably over a four-year period.

On January 28, 2008, McMoRan's Board of Directors granted a total of 1,678,500 stock options to its employees at an exercise price of $15.04 per share, including immediately exercisable options for an aggregate of 445,000 shares, including 400,000 shares, to its Co-Chairmen in lieu of compensation in 2008. Issuance of all stock options granted on January 28, 2008 is subject to the shareholders of McMoRan ratifying a new stock incentive plan at the annual shareholders meeting to be held in June 2008.

On January 31, 2005, McMoRan's Board of Directors granted 452,500 stock options, including immediately exercisable options totaling 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 are exercisable over a four-year period. Pursuant to accounting requirements of APB Opinion No. 25 (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 also recorded noncash compensation charges of $0.4 million related to the immediately exercisable options granted to the Co-Chairmen.

For additional information regarding stock based compensation costs for the three years ended December 31, 2007 see Note 1 – "Stock Based Compensation Costs".

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, 2007, the plan's assets had a fair value of $1.5 million and the shortfall approximated $2.3 million.

McMoRan also provides certain health care and life insurance benefits (Other Benefits) to retired employees. McMoRan has the right to modify or terminate these benefits. For the year ended December 31, 2007, the health care trend rate used for Other Benefits was 9.0 percent in 2008, decreasing ratably annually until reaching 5.0 percent in 2012. For the year ended December 31, 2006, the health care cost trend rate used for the Other Benefits was 9 percent in 2007, 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 (in thousands):

	Pension Benefits		Other Benefits	
	2007	2006	2007	2006
Change in benefit obligation:				
Benefit obligation at the beginning of year	$ (4,372)	$ (4,502)	$ (6,293)	$ (6,300)
Service cost	-	-	(26)	(20)
Interest cost	(214)	(217)	(330)	(347)
Actuarial gains	-	-	588	108
Participant contributions	-	-	(206)	(207)
Benefits paid	807	347	423	473
Benefit obligation at end of year	(3,779)	(4,372)	(5,844)	(6,293)
Change in plan assets:				
Fair value of plan assets at beginning of year	2,231	2,549	-	-
Return on plan assets	100	29	-	-
Employer/participant contributions	-	-	423	473
Benefits paid	(807)	(347)	(423)	(473)
Fair value of plan assets at end of year	1,524	2,231	-	-
Funded status	$ (2,255)	$ (2,141)	$ (5,844)	$ (6,293)
Weighted-average assumptions (percent):				
Discount rate	N/A[a]	N/A[a]	6.00	5.75
Expected return on plan assets	N/A	N/A	-	-
Rate of compensation increase	N/A	N/A	-	-

a. As discussed above, McMoRan elected to terminate its defined benefit pension plan on June 30, 2000. 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 $0.5 million in 2008, $0.6 million in each year ending December 31, 2009, 2010, 2011 and 2012, and a total of $2.7 million during 2013 through 2017. The components of net periodic benefit cost for McMoRan's plans follow (in thousands):

	Pension Benefits			Other Benefits		
	2007	2006	2005	2007	2006	2005
Service cost	$ -	$ -	$ -	$ 26	$ 20	$ 19
Interest cost	214	217	243	330	347	358
Return on plan assets	(100)	(29)	(96)	-	-	-
Amortization of prior service costs	-	-	-	(40)	(40)	(47)
Recognition of net actuarial loss	-	-	-	71	148	114
Net periodic benefit cost	$ 114	$ 188	$ 147	$ 387	$ 475	$ 444

Included in accumulated other comprehensive loss at December 31, 2007 (Note 1), are prior service credits of $0.3 million and actuarial losses of $0.9 million 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). The total amount expected to be recognized into net periodic costs in 2008 associated with these prior service credits and actuarial gains and losses is immaterial.

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 $15,500 for 2007, $15,000 for 2006 and $14,000 for 2005. McMoRan matches 100 percent of each employees' contribution up to a maximum of 5 percent of each employees' annual basic compensation amount. In connection with the termination of its defined benefits plan, 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. Plan participants will vest in McMoRan's matching contributions for both the savings and defined benefit plans upon reaching three years of service with McMoRan. McMoRan's results of operations reflect charges to expense totaling $0.7 million in 2007, $0.5 million in 2006 and $0.4 million in 2005 for its aggregate matching contributions 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 13).

11. INCOME TAXES

McMoRan accounts for income taxes pursuant to SFAS 109, "Accounting for Income Taxes." McMoRan also adopted the provisions of FIN 48 "Accounting for Uncertainties in Income Taxes" effective January 1, 2007 (Note 1). McMoRan has a net deferred tax asset of $264.6 million as of December 31, 2007, resulting from net operating loss carryforwards and other temporary differences related to McMoRan's activities. McMoRan has provided a valuation allowance, including approximately $31.4 million associated with McMoRan's discontinued sulphur operations, for the full amount of these net deferred tax assets. McMoRan's effective tax rate would be impacted in future periods to the extent these deferred tax assets are recognized. Interest or penalties associated with income taxes are recorded as components of the provision for income taxes, although no such amounts have been recognized in the accompanying financial statements. Currently, McMoRan's major taxing jurisdictions are the United States (federal) and Louisiana. McMoRan recently added producing properties in Texas. Tax periods open to audit for McMoRan include federal and Louisiana income tax returns subsequent to 2003.

The components of McMoRan's deferred tax assets (liabilities) at December 31, 2007 and 2006 follow (in thousands):

	December 31,	
	2007	2006
Federal and state net operating loss carryforwards (expiring in varying amounts from 2008-2027)	$ 172,644	$ 170,266
Property, plant and equipment	(43,000)	35,931
Reclamation and shutdown reserves	110,613	18,073
Deferred compensation, postretirement and pension benefits and accrued liabilities	16,644	13,827
Other	7,653	5,940
Less valuation allowance	(264,554)	(244,037)
Net	$ -	$ -

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

	2007		2006		2005	
	Amount	Percent	Amount	Percent	Amount	Percent
Income tax benefit computed at the federal statutory income tax rate	$ 20,907	35 %	$ 16,679	35 %	$ 13,899	35 %
Change in valuation allowance	(20,517)	(34)	(17,030)	(36)	(9,951)	(25)
Other	(390)	(1)	351	1	(3,948)[a]	(10)
Income tax provision	$ -	- %	$ -	- %	$ -	- %

a. Amount primarily reflects the $12.8 million litigation settlement charge (Note 13), which is not deductible for income tax purposes.

12. 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, including rent for the New Orleans corporate headquarters, totaled $5.5 million in 2007, $5.2 million in 2006 and $5.3 million in 2005. 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, 2007 and 2006, McMoRan had an obligation to fund $2.7 million of FM Services costs, primarily reflecting long-term employee pension and postretirement medical obligations (Notes 5 and 10). In 2005, McMoRan paid its approximate $0.5 million obligation related to FM Services' defined benefit plan, which was terminated effective June 30, 2000.

13. COMMITMENTS AND CONTINGENCIES

Commitments. At December 31, 2007, McMoRan had a $57.7 million of contractual commitments related to its planned oil and gas exploration and development activities, including costs related to projects currently in progress, inventory purchase commitments and other exploration expenditures.

Long-Term Contracts and Operating Leases. McMoRan's primary operating leases involve renting office space in two buildings in Houston, Texas, which expire in April 2009 and July 2014, respectively, and office space in Lafayette, Louisiana, which expires November 2011. At December 31, 2007, McMoRan's total minimum annual contractual charges aggregated $7.8 million, with payments totaling $1.4 million in 2008, $1.3 million in 2009, $1.2 million in 2010, $1.1 million in 2011 and 2012, and $1.7 million thereafter.

Other Liabilities. Freeport Energy has a contractual obligation to reimburse a third party a portion of its postretirement benefit costs relating to certain retired former sulphur employees of Freeport Energy. This contractual obligation totaled $7.3 million at December 31, 2007 and $10.6 million at December 31, 2006, including $1.1 million and $2.1 million in current liabilities from discontinued operations, respectively. A third-party actuarial consultant reviews the estimated related future costs associated with this contractual liability on an annual basis using current health care trend costs and incorporating changes made to the underlying benefit plans of the third party. The assessment at year end 2007 used an initial health care cost trend rate of 8.0 percent in 2008 decreasing ratably to 5.0 percent in 2011. During 2006, the assessment used an initial health care cost trend rate of 9 percent in 2007 decreasing ratably to 5 percent in 2011. McMoRan applied a discount rate of 8.5 percent at December 31, 2007 and 7.5 percent at December 31, 2006 to the consultant's future cost estimates. McMoRan reduced the liability by $4.6 million at December 31, 2007, reflecting a decrease in future health claim costs resulting from lower than expected actual health claim reimbursements. McMoRan reduced the liability by $3.2 million at December 31, 2006, primarily to reflect a significant decrease in the number of participants covered by the related benefit plans associated with this contractual liability. Future changes to this estimate resulting from changes in assumptions or actual results varying from projected results will be recorded in earnings.

At December 31, 2007 and 2006, McMoRan had $3.2 million in escrow related to assumed sulphur-related 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. In August 2010, the escrow agreement will terminate and any remaining restricted amounts will be refunded to McMoRan.

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. As of December 31, 2007, 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.

At December 31, 2007 and 2006, McMoRan revised its reclamation and well abandonment estimates recorded under SFAS No. 143 for (1) the initial estimates for the oil and gas properties acquired from Newfield (Note 2); (2) 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; (3) changes in its credit-adjusted risk free interest rate; and (4) assuming additional obligations at some properties and recording obligations relating to any new properties. McMoRan's credit adjusted, risk-free interest rates ranged from 8.51 percent to 10 percent at December 31, 2007, 9.33 percent to 10 percent at December 31, 2006 and 8.35 percent to 10 percent at December 31, 2005. At December 31, 2007, McMoRan's estimated undiscounted reclamation obligations, including inflation and market risk premiums, totaled $486.8 million, including $38.7 million associated with its remaining sulphur obligations. A rollforward of McMoRan's consolidated discounted asset retirement obligations (including both current and long term obligations) follows (in thousands):

	Years Ended December 31,		
	2007	2006	2005
Oil and Natural Gas			
Asset retirement obligation at beginning of year	$ 25,876	$ 21,760	$ 14,429
Liabilities settled	(6,720)	(670)	(4)
Accretion expense [a]	12,222	2,088	1,442
Liabilities assumed in Newfield property acquisition	267,537	-	-
Incurred liabilities	272	2,534	6,978 [b]
Revision for changes in estimates	(4,450)	164	(1,085)
Asset retirement obligations at end of year	$ 294,737	$ 25,876	$ 21,760
Sulphur			
Asset retirement obligations at beginning of year:	$ 23,094	$ 21,786	$ 14,636
Liabilities settled	(3,532) [c]	(3,109) [c]	(55)
Accretion expense	1,738	1,392	960
Revision for changes in estimates	-	3,025 [d]	6,245 [d]
Asset retirement obligation at end of year	$ 21,300	$ 23,094	$ 21,786

a. Accretion expense charges are included within depletion, depreciation and amortization expense in the accompanying consolidated statements of operations.
b. Includes $3.9 million reclamation liability assumed in connection with the termination of the overriding royalty interest in Main Pass' oil production (Note 5). Also includes $2.2 million of assumed reclamation liabilities related to interests in properties which reverted to McMoRan effective June 1, 2005.
c. Amount of costs incurred to remove structures at Port Sulphur that were damaged by hurricanes Katrina and Rita in 2005.
d. Revisions primarily reflect changes in estimated timing of reclamation work at Port Sulphur (Note 9). 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.

At December 31, 2007, McMoRan had $3.7 million in escrow associated with the funding requirements related to the reclamation obligations of the acquired Newfield properties. McMoRan is required to make payments totaling $15 million annually, payable in quarterly installments (twelve payments total), and $5.0 million a year (payable in quarterly installments) thereafter until certain requirements under the arrangement are met.

Litigation. 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.

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 $2.6 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 5).

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.

14. 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,	
	2007	2006
	(In Thousands)	
Unproved properties [a]	$ 70,421	$ 45,237
Proved properties [b]	1,913,907	476,135
Subtotal	1,984,328	521,372
Less accumulated depreciation and amortization	(481,000)	(238,865)
Net oil and gas properties	$ 1,503,328	$ 282,507

a. Includes costs associated with in-progress wells and wells not fully evaluated, including related leasehold acquisition costs, totaling $55.6 million at December 31, 2007 and $38.4 million at December 31, 2006.
b. Includes the costs associated with the Blueberry Hill well at Louisiana State Lease 340, where plans to sidetrack the well are being developed. Amounts totaled $22.9 million at December 31, 2007 and $16.5 million at December 31, 2006.

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

	Years Ended December 31,		
	2007	2006	2005
	(In Thousands)		
Acquisition of properties:			
Proved	$ 1,314,136 [a]	$ -	$ -
Unproved	8,313 [a]	2,310	3,542
Exploration costs	140,874	124,590	88,294
Development costs	59,287	134,338	90,617
	$ 1,522,610	$ 261,238	$ 182,453

a. Includes the costs associated with acquisition of properties from Newfield (Note 2), including $7.5 million attributable to unproved properties.

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 in the period ended December 31, 2007 (in thousands):

	Years Ended December 31,		
	2007	2006	2005
Beginning of year	$ 38,456	$ 19,619	$ 39,270
Additions to capitalized exploratory well costs pending determination of proved reserves	157,216	242,558	163,638
Reclassifications to wells, facilities, and equipment based on determination of proved reserves	(117,259)	(178,777)	(136,465)
Amounts charged to exploration expense	(22,433)	(44,944)	(46,824)
End of year	$ 55,980	$ 38,456	$ 19,619

At December 31, 2007, McMoRan had investments in two wells (Blueberry Hill and JB Mountain Deep) that had been capitalized for a period in excess of one year following the completion of their drilling operations. The Blueberry Hill well encountered four potentially productive zones below 22,200 feet in February 2005. The well has been assigned proved reserves by Ryder Scott Company, L.P. (Ryder Scott), an independent petroleum engineering firm, each of the three years in the period ending December 31, 2007. McMoRan received the specialized equipment necessary to complete the well in the fourth quarter of 2006 and completion activities were completed in the first half of 2007. The well has been unable to produce because of a blockage above the perforated interval. A sidetrack well is being planned to target sands in a down dip position to this original wellbore. McMoRan's net investment in the Blueberry Hill well totaled $22.9 million at December 31, 2007 and $16.5 million at December 31, 2006. The JB Mountain Deep well at South Marsh Island Block 224 reached its total depth of 24,600 feet in April 2006. Wireline logs indicated 120 gross feet of potential hydrocarbon bearing sands at a depth of 21,900 feet and also indicated another 115 gross feet of potential hydrocarbon bearing sands at a depth of 24,250 feet. A protective liner has been set and the well has been temporarily abandoned. Information obtained from the Blueberry Hill well and the Hurricane Deep well at South Marsh Island Block 217, which commenced production in January 2008, will be incorporated in the future plans for the JB Mountain well, as all three areas demonstrate similar geologic settings and are targeting the same deep Miocene sands. McMoRan's investment in the JB Mountain well totaled $29.6 million at December 31, 2007 and 2006.

Proved Oil and Natural Gas Reserves (Unaudited). Proved oil and natural gas reserves for each of the three years in the period ending December 31, 2007 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		
	2007	2006	2005	2007	2006	2005
Proved reserves:						
Beginning of year	5,772 [a]	7,131	4,789	41,202	38,944	21,187
Revisions of previous estimates	925 [a]	(343)	1,137	(3,192)	(349)	(2,150)
Discoveries and extensions	484	536	1,602 [b]	25,552	17,153	27,845 [b]
Production	(2,745)	(1,552)	(850)	(38,994)	(14,546)	(7,938)
Purchase of reserves	15,281 [c]	-	453 [d]	221,038 [c]	-	-
End of year	19,717	5,772 [a]	7,131	245,606	41,202	38,944

	Oil			Natural Gas		
	2007	2006	2005	2007	2006	2005
Proved developed reserves:						
Beginning of year	5,526[a]	6,248	4,640	34,949	29,101	14,765
End of year	17,452	5,526[a]	6,248	203,595	34,949	29,101

a. Includes approximately 46 MBbls of oil associated with the West Cameron Block 43 field that were included in the estimated proved reserve amounts at December 31, 2006 but which McMoRan determined was not recoverable in early 2007 (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 5).
c. Reflects the estimated proved reserves of the properties acquired from Newfield at the August 6, 2007 closing date (Note 2).
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 related to the field (Notes 5 and 13).

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 $92.69 per barrel of oil and $7.22 per Mcf of natural gas at December 31, 2007 and $53.56 per barrel of oil and $6.08 per Mcf of natural gas at December 31, 2006. The oil price reflects the lower market value associated with the sour crude oil reserves produced at Main Pass, whose year-end prices were $85.57 per barrel at December 31, 2007 and $51.77 per barrel at December 31, 2006.

	December 31,	
	2007	2006
	(In Thousands)	
Future cash inflows	$ 3,601,360	$ 560,852
Future costs applicable to future cash flows:		
Production costs	(687,588)	(199,246)
Development and abandonment costs	(585,681)	(46,591)
Future income taxes	(266,928)	(772)
Future net cash flows	2,061,163	314,243[a]
Discount for estimated timing of net cash flows (10% discount rate)[b]	(422,897)	(44,281)
	$ 1,638,266	$ 269,962[a]

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 were determined not to be recoverable in early 2007 (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,		
	2007	2006	2005
	(In Thousands)		
Beginning of year	$ 269,962	$ 383,139	$ 117,289
Revisions:			
Changes in prices	494,774	(106,961)	70,657
Accretion of discount	26,996	38,313	11,729
Change in reserve quantities	196,253	(21,317)	(15,051)
Other changes, including revised estimates of development costs and rates of production	(186,238)	(11,739)	9,204
Discoveries and extensions, less related costs	132,808	93,125	257,432[a]
Development costs incurred during the year	8,559	35,123	8,640
Change in future income taxes	(179,725)	3,862	(4,445)
Revenues, less production costs	(353,123)	(143,583)	(88,607)
Purchase of reserves in place	1,228,000[b]	-	16,291[c]
End of year	$ 1,638,266	$ 269,962	$ 383,139

a. Amount includes $65.5 million relating to the reversion of interests back to McMoRan in properties it previously sold in February 2002 (Note 5).
b. Reflects the fair value of the proved reserves for the properties acquired from Newfield at the August 6, 2007 closing date (Note 2).
c. Reflects the termination of an overriding royalty/net profit interest in the oil production at Main Pass (Note 5).

15. GUARANTOR FINANCIAL STATEMENTS

In November 2007, McMoRan completed the sale of $300 million of 11.875% senior notes (Note 6). The senior notes are unconditionally guaranteed on a senior basis jointly and severally by MOXY and the subsidiary guarantors. The guarantee is an unsecured obligation of the guarantor and ranks equal in right of payment with all existing and future indebtedness of McMoRan, including indebtedness under the credit facility. The guarantee also ranks senior in right of payment with all future subordinated obligations and is effectively subordinated in right of payment to any debt of McMoRan's subsidiaries that are not subsidiary guarantors.

The following consolidating financial information includes information regarding McMoRan, the Parent, MOXY and its subsidiaries, as guarantor, and Freeport Energy, as the non-guarantor subsidiary. Included are the condensed consolidating balance sheets at December 31, 2007 and 2006 and the related condensed consolidating statements of operations and cash flow for the years ended December 31, 2007, 2006 and 2005, which should be read in conjunction with the notes to these consolidated financial statements:

CONDENSED CONSOLIDATING BALANCE SHEET
December 31, 2007

	Parent	MOXY	Freeport Energy	Eliminations	Consolidated McMoRan
			(In Thousands)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ 143	$ 3,446	$ 1,241	$ -	$ 4,830
Accounts receivable	885	127,805	-	-	128,690
Inventories	-	11,507	-	-	11,507
Prepaid expenses	12,833	1,498	-	-	14,331
Fair value of derivative contracts	-	16,623	-	-	16,623
Current assets from discontinued operations	-	-	3,029	-	3,029
Total current assets	13,861	160,879	4,270	-	179,010
Property, plant and equipment, net	-	1,503,328	31	-	1,503,359
Discontinued sulphur assets	-	-	349	-	349
Investment in subsidiaries	971,176	-	-	(971,176)	-
Amounts due from affiliates	-	68,341	5,987	(74,328)	-
Deferred financing costs and other assets	14,135	18,308	127	-	32,570
Total assets	$ 999,172	$ 1,750,856	$ 10,764	$ (1,045,504)	$ 1,715,288
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)					
Current liabilities:					
Accounts payable	222	97,300	299	-	$ 97,821
Accrued liabilities	2,110	65,006	1,176	-	68,292
Current portion of debt	111,535	-	-	-	111,535
Current portion of oil and gas accrued reclamation costs	-	80,839	-	-	80,839
Other current liabilities	11,723	15,333	-	-	27,056
Current liabilities from discontinued operations	-	-	14,769	-	14,769
Total current liabilities	125,590	258,478	16,244	-	400,312
Long-term debt	415,000	274,000	-	-	689,000
Amounts due to affiliates	74,328	-	-	(74,328)	-
Accrued oil and gas reclamation costs	-	213,898	-	-	213,898
Accrued sulphur reclamation costs	-	-	9,155	-	9,155
Other long-term liabilities	12,025	9,245	9,424	-	30,694
Total liabilities	626,943	755,621	34,823	(74,328)	1,343,059
Commitments and contingencies					
Stockholders' equity (deficit)	372,229	995,235	(24,059)	(971,176)	372,229
Total liabilities and stockholders' equity (deficit)	$ 999,172	$ 1,750,856	$ 10,764	$ (1,045,504)	$ 1,715,288

CONDENSED CONSOLIDATING BALANCE SHEET
December 31, 2006

	Parent	MOXY	Freeport Energy	Eliminations	Consolidated McMoRan
			(In Thousands)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ 16,593	$ 1,030	$ 207	$ -	$ 17,830
Restricted investments	5,930	-	-	-	5,930
Accounts receivable	30	45,606	-	-	45,636
Inventories	-	25,034	-	-	25,034
Prepaid expenses	644	12,450	3,096	-	16,190
Current assets from discontinued operations	-	-	6,492	-	6,492
Total current assets	23,197	84,120	9,795	-	117,112
Property, plant and equipment, net	-	282,507	31	-	282,538
Discontinued sulphur assets	-	-	362	-	362
Investment in subsidiaries	164,661	-	-	(164,661)	-
Amounts due from affiliates	-	5,105	-	(5,105)	-
Deferred financing costs and other assets	7,993	545	127	-	8,665
Total assets	$ 195,851	$ 372,277	$ 10,315	$ (169,766)	$ 408,677
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)					
Current liabilities:					
Accounts payable	23	85,347	238	-	$ 85,608
Accrued liabilities	842	28,004	3,894	-	32,740
Current portion of oil and gas accrued reclamation costs	-	2,604	-	-	2,604
Other current liabilities	4,825	654	-	-	5,479
Current liabilities from discontinued operations	-	-	16,587	-	16,587
Total current liabilities	5,690	116,609	20,719	-	143,018
Long-term debt	215,870	28,750	-	-	244,620
Amounts due to affiliates	1,678	-	3,427	(5,105)	-
Accrued oil and gas reclamation costs	-	23,272	-	-	23,272
Accrued sulphur reclamation costs	-	-	10,185	-	10,185
Other long-term liabilities	12,012	2,091	12,879	-	26,982
Total liabilities	235,250	170,722	47,210	(5,105)	448,077
Commitments and contingencies					
Mandatorily redeemable preferred stock	29,043	-	-	-	29,043
Stockholders' equity (deficit)	(68,442)	201,555	(36,895)	(164,661)	(68,443)
Total liabilities and stockholders' equity (deficit)	$ 195,851	$ 372,277	$ 10,315	$ (169,766)	$ 408,677

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
Year Ended December 31, 2007

	Parent	MOXY	Freeport Energy	Eliminations	Consolidated McMoRan
			(In Thousands)		
Revenues:					
Oil and gas	$ -	$ 475,250	$ -	$ -	$ 475,250
Service	-	6,421	-	(504)	5,917
Total revenues	-	481,671	-	(504)	481,167
Costs and expenses:					
Production and delivery costs	-	122,679	(48)	(504)	122,127
Depreciation and amortization	-	256,007	-	-	256,007
Exploration expenses	-	58,954	-	-	58,954
General and administrative expenses	5,264	22,499	210	-	27,973
Loss on oil and gas derivative contracts	-	5,181	-	-	5,181
Start-up costs for Main Pass Energy Hub™	-	-	9,754	-	9,754
Insurance recovery and other	-	(2,338)	-	-	(2,338)
Total costs and expenses	5,264	462,982	9,916	(504)	477,658
Operating income (loss)	(5,264)	18,689	(9,916)	-	3,509
Interest expense	(49,513)	(16,853)	-	-	(66,366)
Equity in earnings (losses) of consolidated subsidiaries	(6,464)	-	-	6,464	-
Other income (expense), net	1,507	(2,211)			(704)
Income (loss) from continuing operations before income taxes	(59,734)	(375)	(9,916)	6,464	(63,561)
Provision for income taxes	-	-	-	-	-
Income (loss) from continuing operations	(59,734)	(375)	(9,916)	6,464	(63,561)
Income from discontinued operations	-	302	3,525	-	3,827
Net income (loss)	(59,734)	(73)	(6,391)	6,464	(59,734)
Preferred dividends and amortization of convertible preferred stock issuance costs	(4,172)	-	-	-	(4,172)
Net income (loss) applicable to common stock	$ (63,906)	$ (73)	$ (6,391)	$ 6,464	$ (63,906)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
Year Ended December 31, 2006

	Parent	MOXY	Freeport Energy	Eliminations	Consolidated McMoRan
			(In Thousands)		
Revenues:					
Oil and gas	$ -	$ 185,852	$ 10,865	$ -	$ 196,717
Service	778	12,033	501	(291)	13,021
Total revenues	778	197,885	11,366	(291)	209,738
Costs and expenses:					
Production and delivery costs	-	48,483	4,942	(291)	53,134
Depreciation and amortization	-	104,063	661		104,724
Exploration expenses	-	67,737	-	-	67,737
General and administrative expenses	5,637	14,982	108	-	20,727
Start-up costs for Main Pass Energy Hub™	-	-	10,714	-	10,714
Exploration expense reimbursement	-	(10,979)	-	-	(10,979)
Insurance recovery and other	(446)	(2,583)	(723)	-	(3,752)
Total costs and expenses	5,191	221,703	15,702	(291)	242,305
Operating income (loss)	(4,413)	(23,818)	(4,336)	-	(32,567)
Interest expense	(10,135)	(68)	-	-	(10,203)
Equity in earnings (losses) of consolidated subsidiaries	(30,228)	-	-	30,228	-
Other income (expense), net	(2,878)	724	208	-	(1,946)
Income (loss) from continuing operations before income taxes	(47,654)	(23,162)	(4,128)	30,228	(44,716)
Provision for income taxes	-	-	-	-	-
Income (loss) from continuing operations	(47,654)	(23,162)	(4,128)	30,228	(44,716)
Income (loss) from discontinued operations	-	77	(3,015)	-	(2,938)
Net income (loss)	(47,654)	(23,085)	(7,143)	30,228	(47,654)
Preferred dividends and amortization of convertible preferred stock issuance costs	(1,615)	-	-	-	(1,615)
Net income (loss) applicable to common stock	$ (49,269)	$ (23,085)	$ (7,143)	$ 30,228	$ (49,269)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
Year Ended December 31, 2005

	Parent	MOXY	Freeport Energy	Eliminations	Consolidated McMoRan
			(In Thousands)		
Revenues:					
Oil and gas	$ -	$ 95,646	$ 22,530	$ -	$ 118,176
Service	1,796	8,416	2,153	(414)	11,951
Total revenues	1,796	104,062	24,683	(414)	130,127
Costs and expenses:					
Production and delivery costs	-	10,843	19,140	(414)	29,569
Depreciation and amortization	-	23,206	2,690	-	25,896
Exploration expenses	-	63,805	-	-	63,805
General and administrative expenses	9,799	9,017	735	-	19,551
Start-up costs for Main Pass Energy Hub™	-	-	9,749	-	9,749
Insurance recovery and other	12,830	-	(8,900)	-	3,930
Total costs and expenses	22,629	106,871	23,414	(414)	152,500
Operating income (loss)	(20,833)	(2,809)	1,269	-	(22,373)
Interest expense	(15,273)	(9)	-	-	(15,282)
Equity in earnings (losses) of consolidated subsidiaries	(7,511)	-	-	7,511	-
Other income (expense), net	3,905	2,012	268	-	6,185
Income (loss) from continuing operations before income taxes	(39,712)	(806)	1,537	7,511	(31,470)
Provision for income taxes	-	-	-	-	-
Income (loss) from continuing operations	(39,712)	(806)	1,537	7,511	(31,470)
Loss from discontinued operations	-	-	(8,242)	-	(8,242)
Net income (loss)	(39,712)	(806)	(6,705)	7,511	(39,712)
Preferred dividends and amortization of convertible preferred stock issuance costs	(1,620)	-	-	-	(1,620)
Net income (loss) applicable to common stock	$ (41,332)	$ (806)	$ (6,705)	$ 7,511	$ (41,332)

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOW
Year Ended December 31, 2007

	Parent	MOXY	Freeport Energy	Consolidated McMoRan
	(In Thousands)			
Cash flow from operating activities:				
Net cash provided by (used in) continuing operations	$ 35,897	$ 189,205	$ (6,040)	$ 219,062
Net cash provided by (used in) discontinued operations	-	302	(11,726)	(11,424)
Net cash provided by (used in) operating activities	35,897	189,507	(17,766)	207,638
Cash flow from investing activities:				
Exploration, development and other capital expenditures	-	(153,210)	-	(153,210)
Acquisition of Newfield properties, net	-	(1,047,936)	-	(1,047,936)
Proceeds from restricted investments	6,056	-	-	6,056
Increase in restricted investments	(126)	-	-	(126)
Net cash provided by (used in) investing activities	5,930	(1,201,146)	-	(1,195,216)
Cash flow from financing activities:				
Net borrowings under revolving credit facility	-	245,250	-	245,250
Proceeds from sale of 11.875% senior notes	300,000	-	-	300,000
Net proceeds from sale of 6.75% mandatory convertible preferred stock	250,385	-	-	250,385
Net proceeds from sale of common stock	200,189	-	-	200,189
Proceeds from bridge loan facility	800,000	-	-	800,000
Repayment of bridge loan facility	(800,000)	-	-	(800,000)
Proceeds from senior term loan	100,000	-	-	100,000
Repayment of senior term loan	(100,000)	-	-	(100,000)
Financing costs	(17,573)	(12,980)	-	(30,553)
Dividends paid on convertible preferred stock	(1,121)	-	-	(1,121)
Proceeds from exercise of stock options, warrants and other	10,428	-	-	10,428
Investment from parent	(800,586)	781,786	18,800	-
Net cash provided by (used in) financing activities	(58,278)	1,014,056	18,800	974,578
Net increase (decrease) in cash and cash equivalents	(16,451)	2,417	1,034	(13,000)
Cash and cash equivalents at beginning of year	16,594	1,029	207	17,830
Cash and cash equivalents at end of year	$ 143	$ 3,446	$ 1,241	$ 4,830

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOW
Year Ended December 31, 2006

	Parent	MOXY	Freeport Energy	Consolidated McMoRan
		(In Thousands)		
Cash flow from operating activities:				
Net cash provided by (used in) continuing operations	$ (25,469)	131,323	(6,311)	99,543
Net cash provided by (used in) discontinued operations	-	77	(4,429)	(4,352)
Net cash provided by (used in) operating activities	(25,469)	131,400	(10,740)	95,191
Cash flow from investing activities:				
Exploration, development and other capital expenditures	-	(251,851)	(518)	(252,369)
Property insurance reimbursement	-	3,947	-	3,947
Proceeds from restricted investments	16,505	-	-	16,505
Increase in restricted investments	(229)	-	-	(229)
Proceeds from sale of oil and gas properties	-	1,021	50	1,071
Cash acquired	-	23,052	(23,052)	-
Net cash provided by (used in) investing activities	16,276	(223,831)	(23,520)	(231,075)
Cash flow from financing activities:				
Net borrowings under revolving credit facility	-	28,750	-	28,750
Financing costs	-	(531)	-	(531)
Dividends paid on convertible preferred stock	(1,494)	-	-	(1,494)
Proceeds from exercise of stock options, warrants and other	389	-	-	389
Payments for induced conversion of convertible senior notes	(4,301)	-	-	(4,301)
Net repayment of borrowings to parent	5,674	(5,674)	-	-
Investment from parent	(17,826)	-	17,826	-
Net cash provided by (used in) financing activities	(17,558)	22,545	17,826	22,813
Net decrease in cash and cash equivalents	(26,751)	(69,886)	(16,434)	(113,071)
Cash and cash equivalents at beginning of year	43,345	70,915	16,641	130,901
Cash and cash equivalents at end of year	$ 16,594	$ 1,029	$ 207	$ 17,830

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOW
Year Ended December 31, 2005

	Parent	MOXY	Freeport Energy	Consolidated McMoRan
		(In Thousands)		
Cash flow from operating activities:				
Net cash provided by (used in) continuing operations	$ (18,518)	$ 87,611	$ 9,151	$ 78,244
Net cash used in discontinued operations	-	-	(4,706)	(4,706)
Net cash provided by (used in) operating activities	$ (18,518)	$ 87,611	$ 4,445	$ 73,538
Cash flow from investing activities:				
Exploration, development and other capital expenditures	-	(153,746)	(7,516)	(161,262)
Property insurance reimbursement	-	-	3,500	3,500
Proceeds from restricted investments	15,150	-	-	15,150
Increase in restricted investments	(502)	-	-	(502)
Net cash used in investing activities	14,648	(153,746)	(4,016)	(143,114)
Net cash used in discontinued operations	-	-	(66)	(66)
Net cash provided by (used in) investing activities	14,648	(153,746)	(4,082)	(143,180)
Cash flow from financing activities:				
Dividends paid on convertible preferred stock	(1,129)	-	-	(1,129)
Proceeds from exercise of stock options, warrants and other	2,363	-	-	2,363
Investment from parent	(70,380)	55,000	15,380	-
Net cash provided by (used in) financing activities	(69,146)	55,000	15,380	1,234
Net increase (decrease) in cash and cash equivalents	(73,016)	(11,135)	15,743	(68,408)
Cash and cash equivalents at beginning of year	116,361	82,050	898	199,309
Cash and cash equivalents at end of year	$ 43,345	$ 70,915	$ 16,641	$ 130,901

16. 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)				
2007					
1st Quarter	$ 51,697	$ (11,923)[b]	$ (14,903)[c]	$ (0.53)	$ (0.53)
2nd Quarter	45,348	685[d]	(6,486)	(0.23)	(0.23)
3rd Quarter [e]	133,252	(25,663)[f]	(52,184)[g]	(1.50)	(1.50)
4th Quarter [e]	250,870[h]	40,410[i]	9,667[j]	0.21	0.20
	$ 481,167	$ 3,509	$ (63,906)		

	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)[k]	$ (13,485)[l]	$ (0.50)	$ (0.50)
2nd Quarter	53,330	17,828	14,090	0.50	0.32
3rd Quarter	60,415	(13,719)[m]	(18,992)	(0.67)	(0.67)
4th Quarter	56,248	(30,298)[n]	(30,882)[o]	(1.09)	(1.09)
	$ 209,738	$ (32,567)	$ (49,269)		

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 a $3.2 million charge to increase the accrual for estimated reclamation costs on two fields and $1.3 million of nonproductive exploratory well drilling and related costs.
c. Includes $4.2 million final settlement of property damage claims for the Port Sulphur, Louisiana facilities.
d. Includes nonproductive exploratory well drilling and related costs of $2.2 million.
e. Amounts associated with the properties acquired from Newfield were recorded prospectively from the August 6, 2007 closing date to December 31, 2007.
f. Includes a $13.6 million impairment charge to write off McMoRan's interest in the Cane Ridge well at Louisiana State Lease 18055, nonproductive exploratory well drilling and related costs of $20.3 million primarily reflecting the results for the Cas well at South Timbalier Block 70, $12.5 million of seismic data purchases for exploration acreage acquired from Newfield and a gain of $10.7 million for non cash mark-to-market adjustments associated with McMoRan's oil and gas derivative contracts (Note 7).
g. Includes $3.0 million prepayment premium paid to terminate the $100 million senior secured term loan on August 7, 2007.
h. Includes $195.4 million associated with the properties acquired from Newfield.
i. Includes the first full quarter of costs associated the properties acquired from Newfield totaling $24.2 million of production and delivery costs and $111.9 million of depreciation, depletion and amortization. Also includes a loss of $15.9 million for non cash mark-to-mark adjustments associated with McMoRan's oil and gas derivative contracts.
j. Includes $8.7 million net charge to write off the remaining unamortized financing costs associated with the bridge loan facility upon its repayment and termination in November 2007 (Note 6) and a $4.6 million reduction in contractual liability covering certain retired former sulphur employees (Note 13).
k. Includes nonproductive exploratory well drilling and related costs of $12.3 million.
l. Includes $4.3 million charge related to McMoRan's debt conversion transactions (Note 6).
m. Includes $18.5 million of nonproductive exploratory well drilling and related costs.

n. 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 3).
o. Includes $3.2 million reduction in contractual liability covering certain retired former sulphur employees (Note 13).

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) Management's Report on Internal Control over Financial Reporting and Report of Independent Registered Public Accounting Firm. The information required to be furnished pursuant to this item is set forth under the captions "Management's Report on Internal Control over Financial Reporting" and "Report of Independent Registered Public Accounting Firm" in Item 8 of this report.

(c) 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 controls over financial reporting.

As previously disclosed, on August 6, 2007, McMoRan Oil & Gas LLC (MOXY), a wholly-owned subsidiary of McMoRan Exploration Co. (McMoRan), completed its acquisition of substantially all proved property interests and related assets of Newfield Exploration Company (Newfield) on the outer continental shelf of the Gulf of Mexico for total cash consideration of approximately $1.1 billion and the assumption of the related reclamation obligations.

We have integrated the acquired properties' operations and have extended our Sarbanes-Oxley Act Section 404 compliance program to include the acquired properties from Newfield. We have reported on our assessment within the time provided by the Sarbanes-Oxley Act and applicable rules relating to business acquisitions.

In addition, as a matter of course, we continue to update our internal controls over financial reporting as necessary to accommodate any modifications to our business processes or accounting procedures.

Item 9B. Other Information

Not Applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

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. Information relating to our Ethics and Business Conduct Policy is included in Part 1, Item 4. Other information required by this item will be contained in our definitive proxy statement to be filed pursuant to Regulation 14A and is incorporated herein by reference.

Item 11. Executive Compensation

Information required by this item will be contained in our definitive proxy statement to be filed pursuant to Regulation 14A and is incorporated herein by reference.

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

Information required by this item will be contained in our definitive proxy statement to be filed pursuant to Regulation 14A and is incorporated herein by reference.

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

Information required by this item will be contained in our definitive proxy statement to be filed pursuant to Regulation 14A and is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services

Information required by this item will be contained in our definitive proxy statement to be filed pursuant to Regulation 14A and is incorporated herein 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.

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.

Blowouts. Accidents resulting from a penetration of a gas or oil reservoir during drilling operations under higher-than-calculated pressure.

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.

Cratering. The collapse of the circulation system dug around the drilling rig for the prevention of blowouts.

Delineation well. A well drilled at a distance from a development well to determine physical extent, reserves and likely production rate of a new oil or gas reservoir.

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.

Gross interval. The measurement of the vertical thickness of the producing and non-producing zones of an oil and gas reservoir.

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

Henry Hub. The pricing point for natural gas futures on the New York Mercantile Exchange.

LNG. Liquefied natural gas

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.

MMbtu. One million british thermal units.

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 hydrocarbon bearing sands. The vertical thickness of the producing zone of an oil and gas reservoir.

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 non-producing reserves. Reserves expected to be recovered from zones in existing wells, which will require additional completion work or future recompletion prior to the start of production.

Proved developed producing reserves. Reserves expected to be recovered from compltion intervals which are open and producing at the time the estimate is made.

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 developed shut-in reserves. Reserves expected to be recovered from (1) completion intervals which are open at the time of the estimate, but which have not stared producing, (2) wells which were shut-in awaiting pipeline connections or as a result of a market interruption or (3) wells not capable of production for mechanical reasons.

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).

Recompletion. An operation whereby a completion in one zone in a well is abandoned in order to attempt a completion in a different zone within the existing wellbore.

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.

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 17, 2008.

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 17, 2008.

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

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

MCMORAN EXPLORATION CO.
EXHIBIT INDEX

Exhibit Number	Exhibit Title	Filed with this Form 10-K	Incorporated by Reference Form	File No.	Date Filed
2.1	Agreement and Plan of Merger dated as of August 1, 1998		S-4	333-61171	10/06/1998
3.1	Amended and Restated Certificate of Incorporation of McMoRan		10-K	001-07791	03/25/1999
3.2	Certificate of Amendment to the Amended and Restated Certificate of Incorporation of McMoRan		10-Q	001-07791	05/13/2003
3.3	Amended and Restated By-Laws of McMoRan as amended effective January 30, 2006		8-K	001-07791	02/03/2006
4.1	Form of Certificate of McMoRan Common Stock		S-4	333-61171	10/06/1998
4.2	Rights Agreement dated as of November 13, 1998		10-K	001-07791	03/25/1999
4.3	Amendment to Rights Agreement dated December 28, 1998		10-K	001-07791	03/25/1999
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		10-Q	001-07791	11/12/1999
4.5	Warrant to Purchase Shares of Common Stock of McMoRan dated September 30, 2003		10-K	001-07791	03/15/2004
4.6	Registration Rights Agreement dated December 16, 2002 between McMoRan and K1 USA Energy Production Corporation		10-K	001-07791	03/27/2003
4.7	Indenture dated as of July 2, 2003 by and between McMoRan and The Bank of New York, as trustee		10-Q	001-07791	08/14/2003
4.8	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		10-Q	001-07791	08/14/2003
4.9	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		8-K	001-07791	10/07/2004
4.10	Indenture dated October 6, 2004 by and among McMoRan and the Bank of New York, as trustee		8-K	001-07791	10/07/2004
4.11	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		8-K	001-07791	10/07/2004
4.12	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		8-K	001-07791	10/07/2004

Exhibit Number	Exhibit Title	Filed with this Form 10-K	Incorporated by Reference		
			Form	File No.	Date Filed
10.1	Main Pass 299 Sulphur and Salt Lease, effective May 1, 1988		10-K	001-07791	04/16/2002
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		10-Q	001-07791	08/14/2002
10.3	Amended and Restated Services Agreement dated as of January 1, 2002 between McMoRan and FM Services Company		10-Q	001-07791	08/14/2003
10.4	Letter Agreement dated August 22, 2000 between Devon Energy Corporation and Freeport Sulphur		10-Q	001-07791	10/25/2000
10.5	Asset Purchase Agreement dated effective December 1, 1999 between SOI Finance Inc., Shell Offshore Inc. and MOXY		10-K	001-07791	02/08/2000
10.6	Employee Benefits Agreement by and between Freeport-McMoRan Inc. and Freeport Sulphur		10-K	001-07791	04/16/2002
10.7	Purchase and Sales agreement dated January 25, 2002 but effective January 1, 2002 by and between MOXY and Halliburton Energy Services, Inc		8-K	001-07791	03/11/2002
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		10-Q	001-07791	05/10/2002
10.9	Purchase and Sale Agreement dated May 9, 2002 by and between MOXY and El Paso Production Company..		10-Q	001-07791	08/14/2002
10.10	Amendment to Purchase and Sale Agreement dated May 22, 2002 by and between MOXY and El Paso Production Company		10-Q	001-07791	08/14/2002
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		10-K	001-07791	03/27/2003
10.12	Purchase and Sale Agreement dated June 20, 2007 by and between Newfield Exploration Company as Seller and McMoRan Oil & Gas LLC as Buyer effective July 1, 2007		8-K	001-07791	06/22/2007
10.13	Amended and Restated Credit Agreement dated as of August 6, 2007, among McMoRan Exploration Co., as parent, McMoRan Oil & Gas LLC, as borrower, JPMorgan Chase Bank, N.A. Merrill Lynch Capital, a division of Merrill Lynch Business Financial Services, Inc., as syndication agent, BNP Paribas, as documentation agent, and the lenders party thereto		10-Q	001-07791	11/01/2007
10.14	Credit Agreement dated as of August 12 2007, among McMoRan Exploration Col, as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and the lenders party thereto		10-Q	001-07791	11/01/2007
10.15*	McMoRan Adjusted Stock Award Plan, as amended		10-Q	001-07791	05/10/2007

Exhibit Number	Exhibit Title	Filed with this Form 10-K	Incorporated by Reference		
			Form	File No.	Date Filed
	and restated				
10.16*	McMoRan 1998 Stock Option Plan, as amended and restated		10-Q	001-07791	05/10/2007
10.17*	McMoRan 1998 Stock Option Plan for non-Employee Directors		10-Q	001-07791	05/10/2007
10.18*	McMoRan Form of Notice of Grant of Nonqualified Stock Options under the 1998 Stock Option Plan		10-Q	001-07791	08/04/2005
10.19*	McMoRan 2000 Stock Incentive Plan, as amended and restated		10-Q	001-07791	05/10/2007
10.20*	McMoRan Form of Notice of Grant of Nonqualified Stock Options under the 2000 Stock Incentive Plan		10-Q	001-07791	08/04/2005
10.21*	McMoRan 2001 Stock Incentive Plan, as amended and restated		10-Q	001-07791	05/10/2007
10.22*	McMoRan 2003 Stock Incentive Plan, as amended and restated		10-Q	001-07791	05/10/2007
10.23*	McMoRan's Performance Incentive Awards Program as amended effective February 1, 1999		10-K	001-07791	03/25/1999
10.24*	McMoRan Form of Notice of Grant of Nonqualified Stock Options under the 2001 Stock Incentive Plan		10-Q	001-07791	08/04/2005
10.25*	McMoRan Form of Restricted Stock Unit Agreement Under the 2001 Stock Incentive Plan		10-Q	001-07791	08/09/2007
10.26*	McMoRan Exploration Co. Executive Services Program		8-K	001-07791	05/05/2006
10.27*	McMoRan Form of Notice of Grants of Nonqualified Stock Options under the 2003 Stock Incentive Plan		10-Q	001-07791	08/04/2005
10.28*	McMoRan Form of Restricted Stock Unit Agreement Under the 2003 Stock Incentive Plan		10-Q	001-07791	08/09/2007
10.29*	McMoRan 2004 Director Compensation Plan, as amended and restated		10-Q	001-07791	05/10/2007
10.30*	Form of Amendment No. 1 to Notice of Grant of Nonqualified Stock Options under the 2004 Director Compensation Plan		8-K	001-07791	05/05/2006
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		10-K	001-07791	03/25/1999
10.32*	Supplemental Letter Agreement between FM Services Company and B.M. Rankin, Jr. effective as of January 1, 2008	X			
10.33*	McMoRan Director Compensation		10-K	001-07791	03/15/2005
10.34*	McMoRan Exploration Co. 2005 Stock Incentive Plan		10-Q	001-07791	05/10/2007
10.35*	Form of Notice of Grant of Nonqualified Stock Options under the 2005 Stock Incentive Plan		8-K	001-07791	05/06/2005
10.36*	Form of Restricted Stock Unit Agreement under the		10-Q	001-07791	08/09/2007

Exhibit Number	Exhibit Title	Filed with this Form 10-K	Incorporated by Reference		
			Form	File No.	Date Filed
	2005 Stock Incentive Plan				
12.1	Computation of Ratio of Earnings to Fixed Charges	X			
14.1	Ethics and Business Conduct Policy		10-K	001-07791	03/15/2004
21.1	List of subsidiaries	X			
23.1	Consent of Ernst & Young LLP	X			
23.2	Consent of Ryder Scott Company, L.P.	X			
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	X			
24.2	Powers of Attorney pursuant to which this report has been signed on behalf of certain officer and directors of McMoRan	X			
31.1	Certification of Principal Executive Officer pursuant to Rule 13a–14(a)/15d-14(a)	X			
31.2	Certification of Principal Financial Officer pursuant to Rule 13a–14(a)/15d-14(a)	X			
32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. Section 1350	X			
32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. Section 1350	X			

* Indicates management contract or compensatory plan or arrangement.

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, 2) 2007
President
New Orleans Market Regions Bank

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

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.

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

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, BNY Mellon Shareowner Services.

BNY Mellon Shareowner Services
480 Washington Boulevard
Jersey City, NJ 07310-8015
888.208.1794
www.bnymellon.com/shareowner/isd

McMoRan Exploration Co.

1615 POYDRAS STREET
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