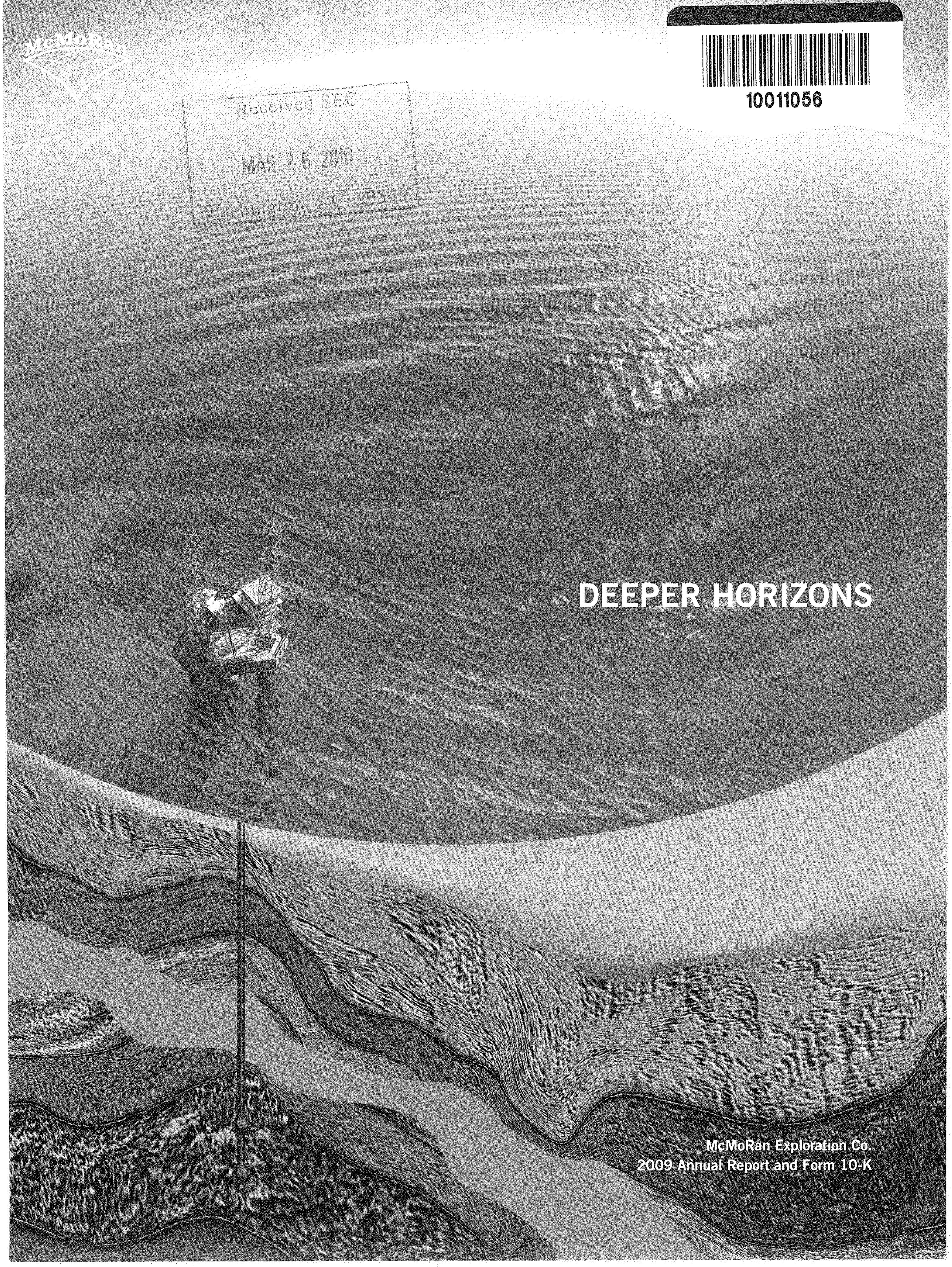
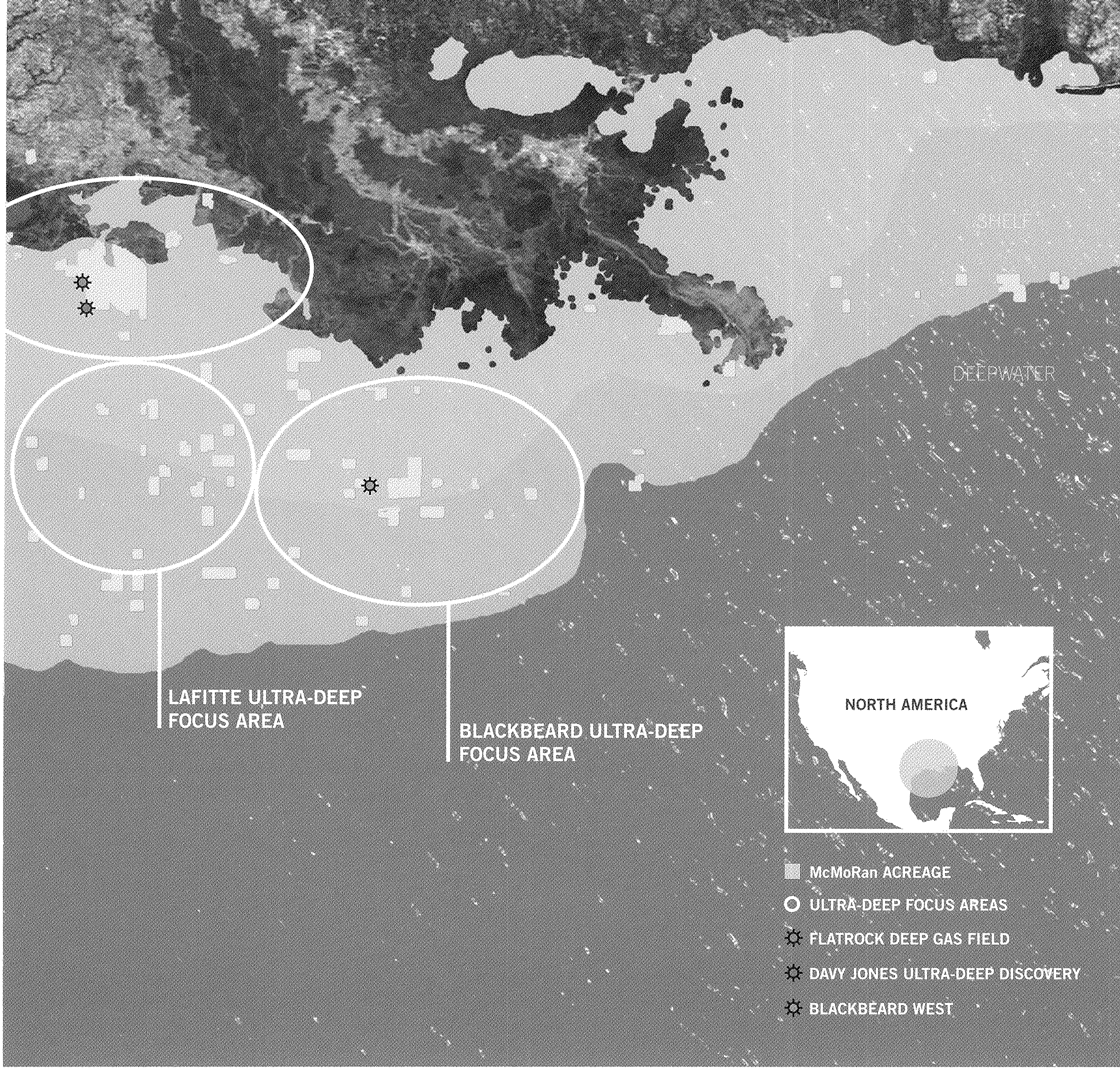


DEEPER HORIZONS

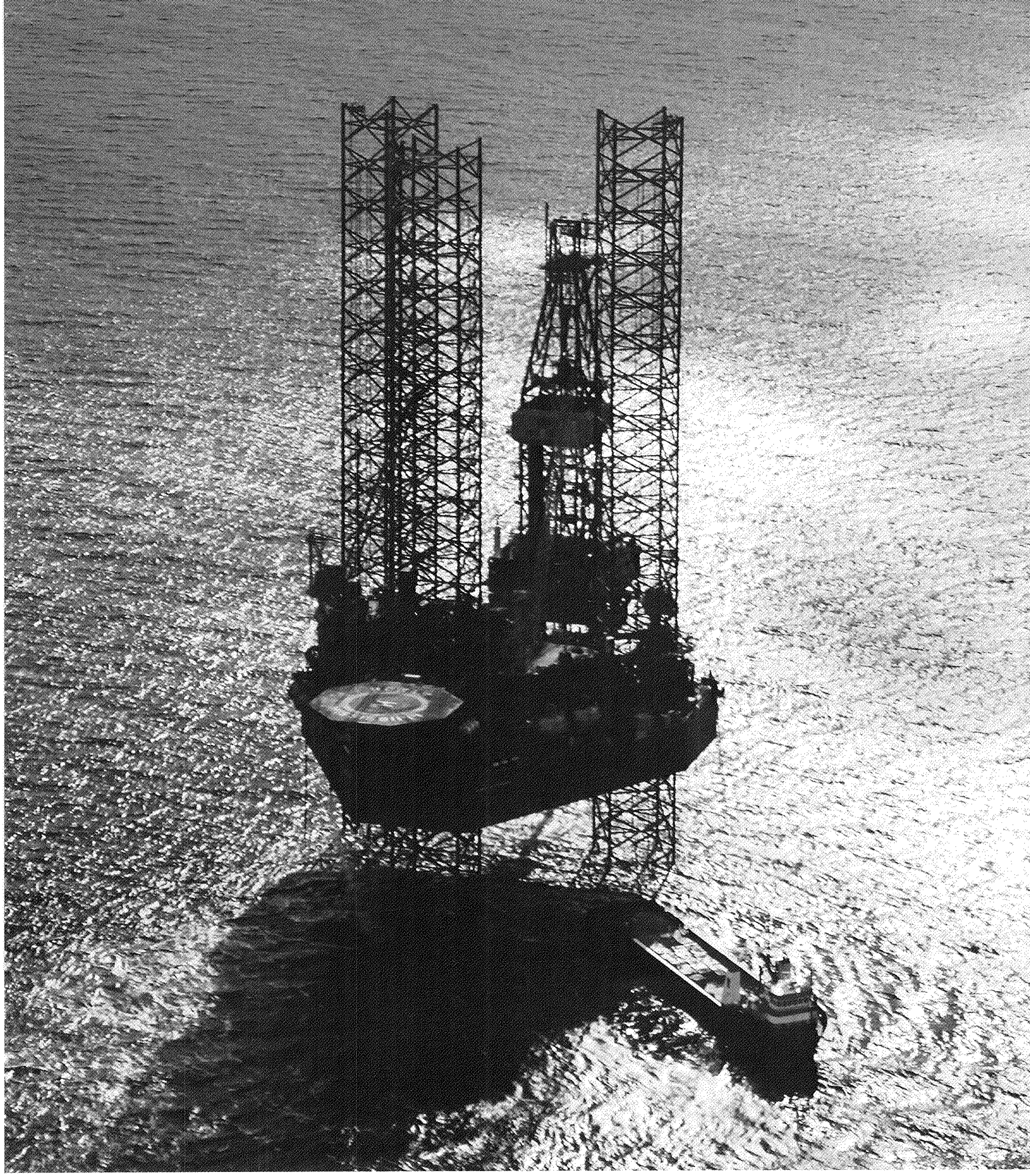
McMoRan Exploration Co.
2009 Annual Report and Form 10-K


DAVY JONES ULTRA-DEEP
FOCUS AREA
100'
SHELF
650'
DEEPWATER
GULF OF MEXICO



McMoRan Exploration Strategy

McMoRan's exploration strategy is focused on two extraordinary opportunities: (1) the "deep gas play," drilling to depths of between 15,000 to 25,000 feet in the shallow waters of the Gulf of Mexico and Gulf Coast area and (2) the "ultra-deep gas play" of depths below 25,000 feet. McMoRan is one of the largest acreage holders on the Shelf of the Gulf of Mexico with rights to approximately one million gross acres, including approximately 150,000 gross acres associated with the ultra-deep gas play.



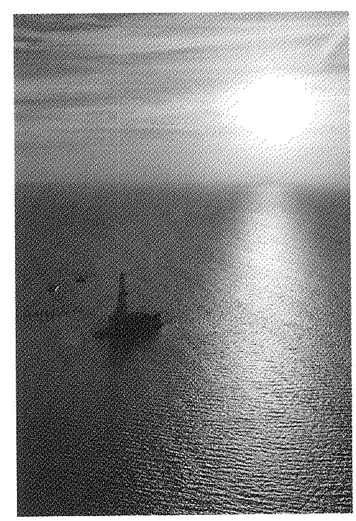
McMoRan is utilizing jack-up rigs to drill its ultra-deep prospects and plans to maintain an active ultra-deep drilling program in 2010.

To Our Shareholders

During 2009, McMoRan Exploration Co. continued its active exploration and development activities on the Shelf of the Gulf of Mexico. Our highly experienced team of explorationists, geoscientists and engineers remained focused on executing our plans to test high-potential prospects below 15,000 feet in the shallow waters of the Gulf of Mexico. Our exciting ultra-deep discovery in January 2010 at Davy Jones garnered significant industry attention as McMoRan leads the way to redefine the subsurface geologic landscape on the Gulf of Mexico Shelf.

Our exciting ultra-deep discovery in January 2010 at Davy Jones garnered significant industry attention as McMoRan leads the way to redefine the subsurface geologic landscape on the Gulf of Mexico Shelf.

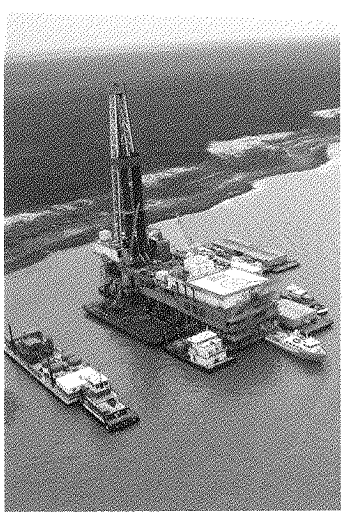
The title of this year's annual report, "Deeper Horizons," highlights the expanded opportunities we have to drill "deep gas" targets between 15,000 feet and 25,000 feet and "ultra-deep" targets below 25,000 feet. Few wells have been drilled at these depths on the Shelf. Our success at the Flatrock field demonstrated the validity of our "deep gas" model. Our geologic models for the "ultra deep" targets indicate the potential for large accumulations of hydrocarbons, comparable in size to discoveries in the deepwater of the Gulf of Mexico in recent years. Results from the Davy Jones and Blackbeard prospects confirm our "ultra-deep" model and provide additional confidence in the prospectivity of this exciting new exploration frontier. The potential of this play is significant. Because these prospects are in shallow water and generally near infrastructure, successful wells can be brought on production more quickly and at a lower cost than new discoveries in the deepwater.



Deep gas prospects are generally located in shallow water depths (15 feet or less), which allows McMoRan to utilize barge rigs to drill and evaluate prospects.

The initial well at our Davy Jones ultra-deep prospect, which encompasses 20,000 acres in 20 feet of water, commenced drilling in 2009 and reached 29,000 feet in February 2010. We announced a major discovery in January 2010, with log results indicating 200 net feet of pay in the Eocene/Paleocene (Wilcox) section. All of the zones were identified to be full to base. Confirmation drilling, if successful, could make Davy Jones one of the largest discoveries on the Shelf of the Gulf of Mexico in decades. We are developing plans to complete and flow test this important well. The timing of the test

Our Flatrock field development in our deep gas program has been a significant success story. The field was discovered in mid-2007 and six successful wells have been brought on production.



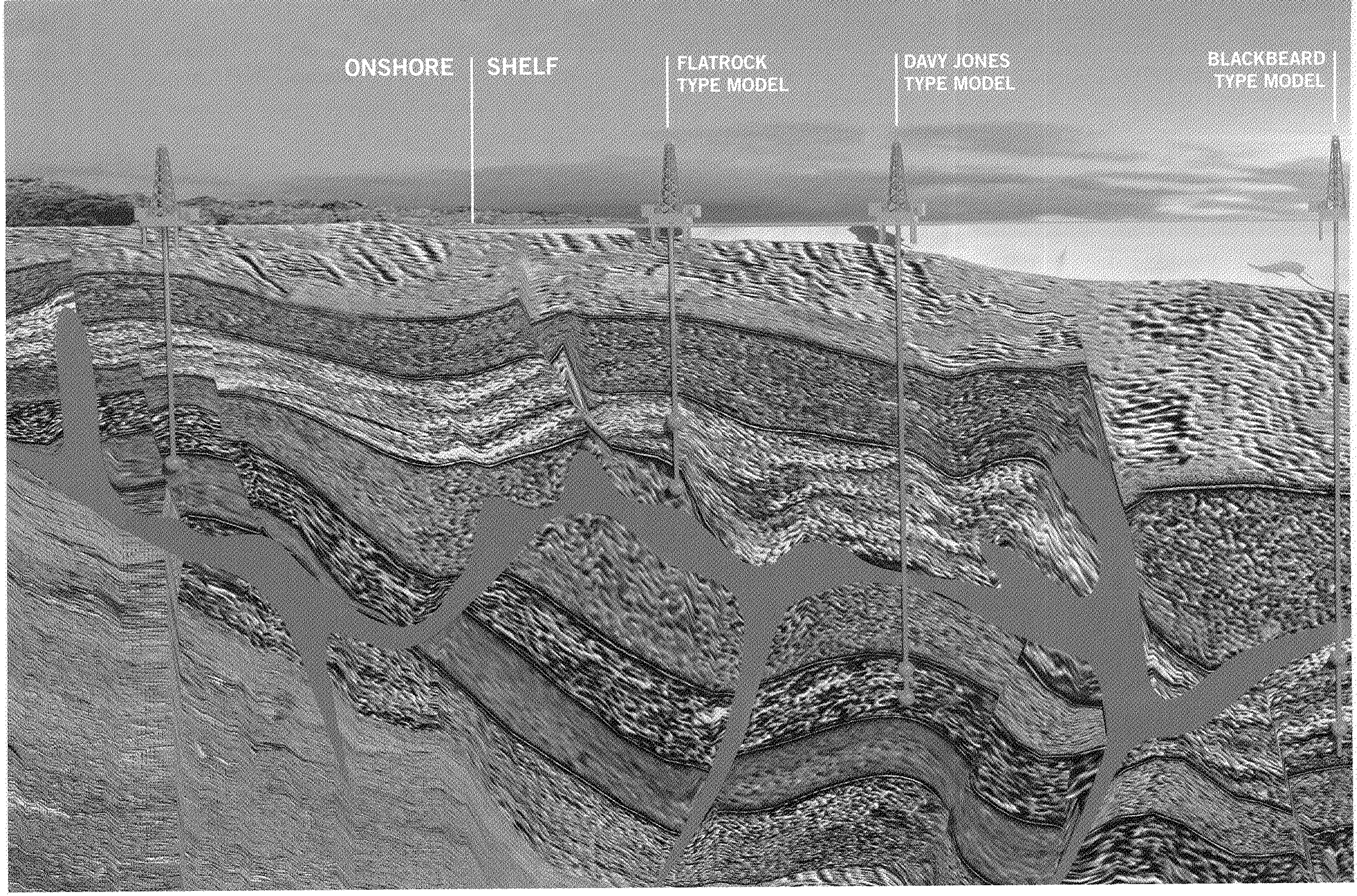
is dependent upon the availability of necessary equipment required to handle the pressures and temperatures encountered in the well.

In our deep gas program, we reported positive results at our Blueberry Hill prospect, located 11 miles southeast of Flatrock. We are currently drilling an offset well to further evaluate the prospect. We have 150,000 gross acres in this area, the cornerstone lease position of our "deep gas" program, which encompasses the deeper expression of the shallower Mound Point and Tiger Shoal fields, where other operators produced over 6 trillion cubic feet of natural gas equivalents historically.

Our 2009 production averaged over 200 MMcfe/d. Our team effectively managed our production and development activities throughout the year, particularly in restoring production previously shut in as a result of the 2008 hurricanes. Our Flatrock field development has been a significant success story. The field was discovered in mid-2007 and six wells have been brought online, averaging 272 MMcfe/d gross in the fourth quarter of 2009. We have produced 123 billion cubic feet of natural gas equivalents (Bcfe) gross through 2009. Independent engineers estimate the field has remaining gross reserves of 258 Bcfe as of December 31, 2009. We own a 25 percent working interest in Flatrock.

Independent reservoir engineers' estimates of our proved oil and gas reserves as of December 31, 2009, were 271.9 Bcfe. These estimates do not include any reserves from the Davy Jones ultra-deep discovery, which was logged in January 2010. Based on our initial data gathered to date, we believe that Davy Jones could add significantly to our reserves in future periods.

The year 2009 also brought about many challenges from the effects of the global recession on financial markets and from significant change in the U.S. natural gas market. We responded by managing our capital spending prudently, entering into new drilling arrangements with partners and improving our balance sheet and liquidity position so that we can continue to expose our shareholders to the opportunities

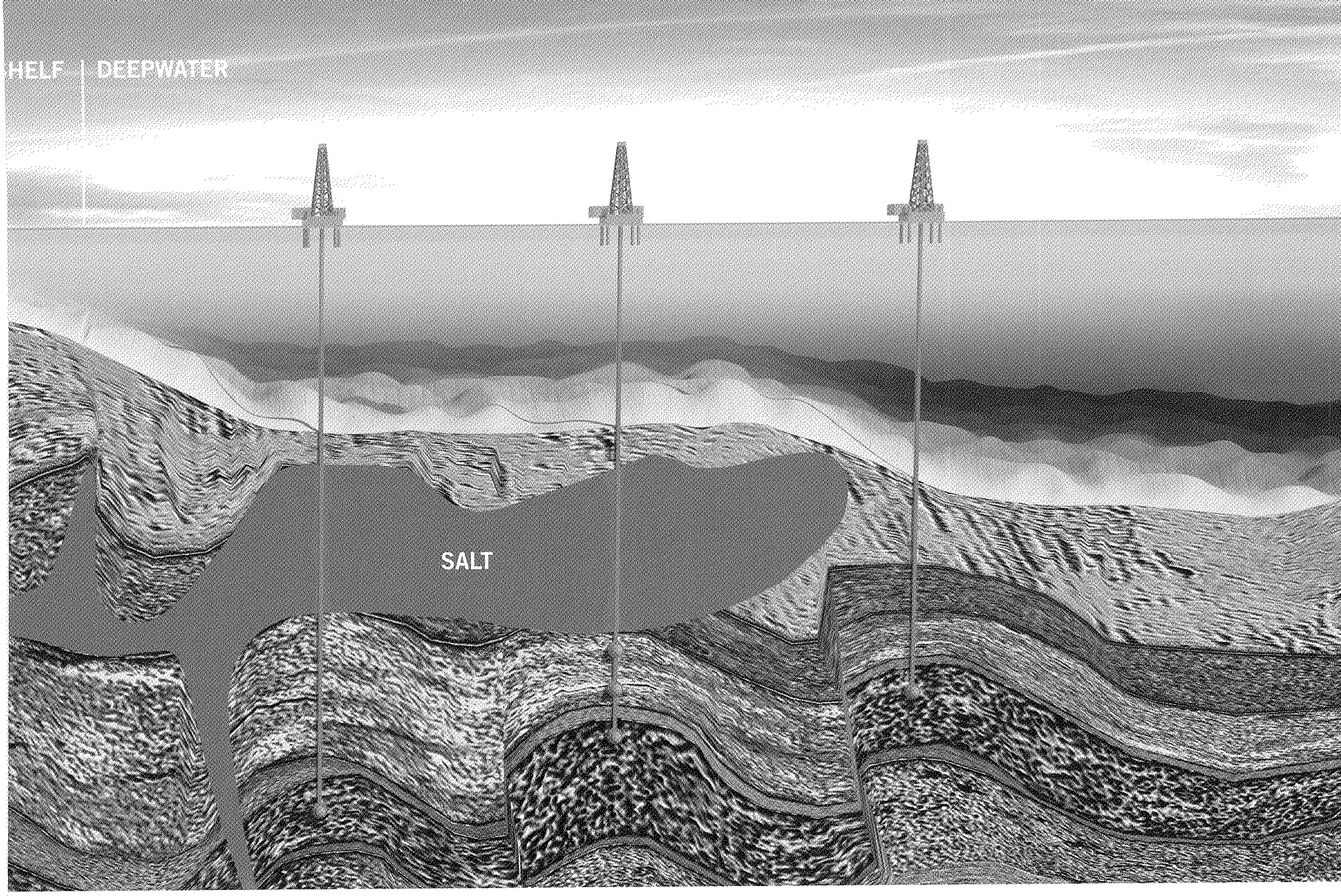


The data received to date from ultra-deep drilling on the Shelf at Davy Jones and Blackbeard West (South Timbalier Block 168) confirm our original geologic modeling, which correlates our objective sections on the Shelf below the salt weld (i.e., listric fault) in the Miocene and older age sections to those productive sections seen in deepwater discoveries by other industry participants.

from our exploration activities. During the year, we completed common and preferred stock offerings that generated $168 million in proceeds. We ended the year with $241 million in cash.

We are looking forward to an eventful year in 2010 as we build upon the success of our exploration activities. We anticipate commencing drilling of three wells in our high potential ultra-deep program, including an offset appraisal well at Davy Jones, an exploration well at Blackbeard East and an initial well at the Lafitte Prospect. The information gained from our drilling activities will enable us to determine the priorities of future operations at our Blackbeard West prospect. We are also planning an active deep gas drilling program.

We are excited by the special opportunities available to us and look forward to reporting on our progress during 2010 and beyond.



We appreciate the dedication and energy of our team who continue to lead the way in this new exploration frontier. We value the counsel of our Board who continue to guide our strategy.

Warmest Regards,

James R. Moffett
Co-Chairman of the Board

Glenn A. Kleinert
President and Chief Executive Officer

Richard C. Adkerson
Co-Chairman of the Board

March 12, 2010

McMoRan EXPLORATION CO.

2009 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, 2009
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

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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period than the registrant was required to submit and post such files). ☐ 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 $1.4 billion on February 26, 2010, and approximately $461.2 million on June 30, 2009.

On February 26, 2010, there were issued and outstanding 92,358,771 shares of the registrant's Common Stock and on June 30, 2009, there were issued and outstanding 86,032,240 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of our Proxy Statement for our 2010 Annual Meeting to be held on May 3, 2010 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, 2009

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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 90.

BUSINESS

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 of the United States. 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 capitalize on our geological, engineering and production strengths in these areas where we have more than 35 years of operating experience. We also believe that the scale of our operations in the Gulf of Mexico allows us to realize certain operating synergies and provides 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. Separate from our oil and gas operations, our long-term business objectives may include the pursuit of multifaceted energy services development of the Main Pass Energy Hub™ (MPEH™), through our wholly owned subsidiary, Freeport-McMoRan Energy LLC (Freeport Energy) (see "Main Pass Energy Hub™ Project" below).

Our technical and operational expertise is primarily in the Gulf of Mexico. We leverage our expertise by attempting to identify exploration opportunities with high potential. Our exploration strategy is focused on the "deep gas play," drilling to depths of between 15,000 to 25,000 feet in the shallow waters of the Gulf of Mexico and Gulf Coast area and on the "ultra-deep gas play" of depths below 25,000 feet. Deep gas prospects target large structures above the salt weld (i.e. listric fault) in the Deep Miocene. Ultra-deep prospects target objectives below the salt weld in the Miocene and older age sections that have been correlated to those productive sections seen in deepwater discoveries by other industry participants. When we find commercially exploitable oil or natural gas, a significant advantage to our exploration strategy is that the infrastructure to support the production and delivery of product is in most cases already in place and available. We believe this presents us with a material competitive advantage in bringing our discoveries on line and lowering related development costs.

We also have significant expertise in various exploration and production technologies, including the incorporation of 3-D seismic interpretation capabilities with traditional structural geological techniques, offshore drilling to significant total depths and horizontal drilling. We employ 63 oil and gas technical professionals, including geophysicists, geologists, petroleum engineers, production and reservoir engineers and technical professionals, most of whom have considerable experience in their respective fields. We also own or have rights to an extensive seismic database, including 3-D seismic data on substantially all of our acreage. We continue to focus on enhancing reserve and production growth in the Gulf of Mexico by applying these technologies.

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

- allocating investment capital based on the potential risk and reward for each exploratory and development opportunity;
- utilizing advanced seismic applications in combination with traditional analysis;

- employing professionals with geophysical, geological and reservoir assessment expertise;
- using new technology applications in drilling and completion practices; and
- increasing the efficiency of our production practices.

Our experience and recognition as an industry leader in drilling deep wells in the Gulf of Mexico also provides us with opportunities to partner with other established oil and gas companies. We have taken, and expect to continue, to take advantage of desirable partnering opportunities as they arise. These partnerships, which typically involve the exploration of our identified prospects or prospects that are brought to us by third parties, allow us to diversify our risks and better manage costs.

We intend to continue to focus on pursuing opportunities within our expanded asset base and actively develop and exploit our recently announced Davy Jones ultra-deep discovery. We may also seek additional financing for our future drilling and development activities. Capital spending will continue to be driven by opportunities and will be managed based on available cash and cash flow, including potential participation by new partners in projects.

PROPERTIES

Oil and Gas Reserves. In December 2008, the SEC adopted new rules which revised oil and gas reserve estimation and disclosure requirements. Among other things, the new rules which became effective for annual reporting periods ending on or after December 31, 2009 (i) allow the use of new technologies to determine proved reserves, (ii) permit the optional disclosure of probable and possible reserves, (iii) modify the prices to estimate reserves for SEC disclosure purposes to a 12-month average price instead of a period-end price, and (iv) require that if a third party is primarily responsible for preparing or auditing the reserve estimates, the company make disclosures relating to the independence and qualifications of the third party, including filing as an exhibit any report received from the third party. Our adoption of these rules did not have a significant impact on estimates of our proved reserves, and we have chosen not to voluntarily disclose our probable or possible reserves.

Proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The term “reasonable certainty” implies a high degree of confidence that the quantities of oil and natural gas actually recovered will equal or exceed the estimate. Our estimated proved oil and natural gas reserves at December 31, 2009 totaled 271.9 Bcfe, of which 66 percent represented natural gas reserves.

All of our proved reserve estimates were prepared by Ryder Scott Company, L.P. (Ryder Scott), an independent petroleum engineering firm, in accordance with the current definitions and guidelines established by the SEC. To achieve reasonable certainty, Ryder Scott employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information and property ownership interests. Among other things, the accuracy of the estimates of our reserves is a function of:

- the quality and quantity of available data and the engineering and geological interpretation of that data;
- estimates regarding the amount and timing of future operating costs, severance taxes, development costs and workovers, all of which may vary considerably from actual results;
- the accuracy of various mandated economic assumptions such as future prices of oil and natural gas; and
- the judgment of the persons preparing the estimates.

The scope and results of the procedures employed by Ryder Scott are summarized in a letter that is filed as an exhibit to this Annual Report on Form 10-K. There is a primary technical person from Ryder Scott responsible for overseeing the preparation of our reserve estimates. He has a Bachelor of Science degree in Petroleum Engineering, is a Licensed Professional Engineer in the State of Texas and is a

Registered Professional Engineer in the State of Louisiana. He also has over 41 years of experience in the estimation and evaluation of petroleum reserves and has attained the professional qualifications as a Reserve Estimator set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

We also maintain an internal staff of reservoir engineers and geoscientists who work closely with Ryder Scott in connection with their preparation of our reserve estimates, including assessing the integrity, accuracy and timeliness of the methods and assumptions used in this process. The activities of our internal staff are led and overseen by an Executive Vice President with over 40 years of technical experience involving petroleum reserve assessment and estimation and geoscience-based evaluation. He is assisted by our Manager of Reservoir Engineering, who has over 25 years of technical experience in petroleum engineering and reservoir evaluation and analysis. Together, these individuals direct the activities of our internal reservoir engineering staff who coordinate with our land, marketing, accounting and other departments to provide the appropriate data to Ryder Scott in support of the reserve estimation process. This process is coordinated and completed on a semi-annual basis (as of June 30 and December 31). To the extent any operational or other matters occur during periods between these semi-annual assessments that significantly impact previous reserve estimates, adjustments to those estimates are recognized at that time.

Because these estimates depend on many assumptions, any or all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and natural gas that we ultimately recover.

The following table discloses our estimated proved reserves as of December 31, 2009. The reserve volumes were determined using the methods prescribed by the SEC, which for 2009 require the use of an average price, calculated as the twelve-month average of the first day of the month prices as adjusted for location and quality differentials (twelve-month average price).

	Gas (MMcf)	Oil and condensate (MBbls)	Total (Bcfe)
Proved developed:			
Producing	47,970	4,842	77.0
Non-producing	78,969	8,198	128.1
Shut-in	8,211	443	10.9
Total proved developed	135,150	13,483	216.0
Proved undeveloped	43,672	2,036	55.9
Total proved reserves	178,822	15,519	271.9

In January 2010, we logged 200 net feet of pay in multiple Eocene/Paleocene (Wilcox) sands in our Davy Jones discovery well. The reserve amounts reflected above do not include reserves attributable to this well. We are currently preparing the well for temporary abandonment pending the delivery and installation of specialized completion equipment. Additional testing (which may require a significant amount of time) will be required to fully assess the extent and classification of reserves to be assigned with respect to this discovery.

Our proved undeveloped reserves are 21 percent of our total proved reserves as of December 31, 2009. During the year ended December 31, 2009, we converted approximately 6 percent of our December 31, 2008 proved undeveloped reserves into proved reserves through development drilling activity at our Flatrock field at a cost of $14.5 million. As of December 31, 2009, none of our proved reserves had been classified as proved undeveloped for more than five years, and the majority of the properties for which we have proved undeveloped reserves have ongoing production from currently developed zones.

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 reconciled to the standardized measure of discounted net cash flows as of December 31, 2009 (in thousands).

	Proved Reserves		
	Developed	Undeveloped	Total
Estimated undiscounted future net cash flows before income taxes	$ 380,147	$ 105,178	$ 485,325
Present value of estimated future net cash flows before income taxes (PV-10) [a, b]	$ 288,405	$ 61,452	$ 349,857
Discounted future income taxes			(1,476)
Standardized measure of discounted net cash flows			$ 348,381

a. Calculated based on the twelve month average prices during 2009 and costs prevailing at December 31, 2009 and using a 10 percent per annum discount rate as required by the SEC. The weighted average price for all properties with proved reserves was $58.73 per barrel of oil and $4.16 per Mcf of natural gas.

b. Present value of estimated future net cash flows before income taxes (PV-10) is considered a non-GAAP financial measure as defined by the SEC. We believe that our PV-10 presentation is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves before taking into account the related future income taxes, as such taxes may differ among various companies because of differences in the amounts and timing of deductible basis, net operating loss carryforwards and other factors. We believe investors and creditors use our PV-10 as a basis for comparison of the relative size and value of our proved reserves to the reserve estimates of other companies. PV-10 is not a measure of financial or operating performance under GAAP and is not intended to represent the current market value of our estimated oil and natural gas reserves. PV-10 should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP (Note 18).

The following table illustrates the sensitivity of our estimated proved oil and natural gas reserves and PV-10 to changes in product price levels. The reserve quantities and PV-10 shown below were prepared on the same basis as in the table above, except for the use of year-end market pricing based on closing forward prices on the New York Mercantile Exchange (NYMEX) for oil and natural gas on December 31, 2009 rather than monthly average prices specified by SEC rules. Natural gas prices were $5.77 per MMbtu for 2010 and increased to $8.30 per MMbtu over the life of the properties and oil prices were $81.73 per barrel for 2010 and increased to $101.92 per barrel over the life of the properties.

	Gas (MMcf)	Oil and condensate (MBbls)	Total (Bcfe)	PV-10 (in millions)[a]
NYMEX price scenario	187,967	17,074	290.4	$1,043

a. See note b. to the preceding table for discussion of PV-10 as a non-GAAP financial measure.

Production, Unit Prices and Costs. Average daily production from our properties, net to our interests, approximated 202 MMcfe/d in 2009, 245 MMcfe/d in 2008 and 152 MMcfe/d in 2007.

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,		
	2009	2008	2007
Net natural gas production (Mcf)	50,081,900	59,886,900	38,994,000
Net crude oil and condensate production, excluding Main Pass 299(Bbls)	2,474,400	3,072,000	1,821,900
Net crude oil production from Main Pass 299 (Bbls)	495,500	561,400	564,000
Net plant product production (per Mcf equivalent)	5,759,600	8,004,400	2,153,000
Average sales prices:			
Natural gas (per Mcf)	$ 4.22	$ 9.96	$ 7.01
Crude oil and condensate, excluding Main Pass 299 (per Bbl)	60.19	106.28	80.19
Crude oil and condensate, Main Pass 299 (per Bbl)	60.35	91.60	64.61
Production (lifting) costs: [a]			
Per barrel for Main Pass [b]	$38.15	$69.29	$44.17
Per Mcfe for other properties [c]	2.47	2.56	1.88

a. 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.

b. Production costs for Main Pass 299 are significantly higher than the production costs for our other properties primarily because of the sour crude oil that is produced at Main Pass 299. Production costs for Main Pass 299 included workover expenses of approximately $1.0 million or $1.95 per barrel in 2009, $17.0 million or $30.22 per barrel in 2008 and $1.8 million or $3.17 per barrel in 2007.

c. 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 $31.2 million or $0.44 per Mcfe in 2009, $45.8 million or $0.53 per Mcfe in 2008 and $19.7 million or $0.38 per Mcfe in 2007.

Acreage. As of December 31, 2009, we owned or controlled interests in 352 oil and gas leases in the Gulf of Mexico and onshore Louisiana and Texas covering approximately 0.97 million gross acres (0.48 million acres net to our interests). Our acreage position on the outer continental shelf includes 0.77 million gross acres (0.42 million acres net to our interests). Less than 0.1 million of our net leasehold interests are scheduled to expire in 2010. A portion of these expirations are held by "Suspension of Operations" (SOO) approvals from the Minerals Management Service (MMS) as discussed below. 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, 2009. 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 2 of our consolidated financial statements.

	Developed		Undeveloped	
	Gross Acres	Net Acres	Gross Acres	Net Acres
Offshore (federal waters)	547,773	315,814	223,678	106,653
Onshore Louisiana and Texas	35,943	18,250	61,775	24,398
Total at December 31, 2009	583,716	334,064	285,453	131,051

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 with drilling depths 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 and ultra deep shelf prospects, and generally on those prospects located beneath shallow reservoirs where significant reserves have already been produced.

The following table identifies our top ten producing properties as of December 31, 2009.

	Working Interest	Net Revenue Interest	Water Depth	Production [a] Gross	Production [a] Net
	(%)	(%)	(feet)	(MMcfe/d)	(MMcfe/d)
Deep Shelf:					
South Marsh Island Block 212 "Flatrock" [b]	25.0	17.7-18.8	10	272	50
Louisiana State Lease 18090 "Long Point" [b]	37.5	26.7	8	29	8
Eugene Island Block 182 [c,d]	66.9	52.8-63.6	91	14	8
"Laphroaig" [c]	37.3	28.5	<10	21	6
Traditional Shelf:					
Eugene Island Block 346 [c]	50.0	39.2	326	20	8
Eugene Island Block 251 [c]	56.9	43.9	160	18	8
South Timbalier Block 193 [c,d]	62.8-72.8	46.8-53.0	114	16	7
South Timbalier Block 299 [c]	75.0	62.5	314	11	7
Main Pass Block 299 [c]	100.0	83.3	210	9	7
South Marsh Island Block 146 [c]	92.0	76.8	240	8	7

a. Reflects average daily production rates for the fourth quarter of 2009.
b. We were the operator for drilling exploratory wells at these prospects. We relinquished being operator following successful completion of the related wells.
c. We operate these properties.
d. 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 and no proved reserves from our ultra-deep shelf properties, which include our recently announced Davy Jones discovery and the Blackbeard West (South Timbalier Block 168) well (see "Oil and Gas Activities—Discoveries and Development Activities below). We have rights to 142,300 gross acres associated with the ultra-deep gas play. At December 31, 2009, approximately 39,500 gross acres associated with our ultra-deep gas play were held by SOO approval from the MMS and are expected to be maintained by drilling or renewal during 2010. In addition, we had 5,000 acres associated with our ultra-deep gas play which are scheduled to expire in 2010. We continue to work towards identifying "deeper pool" exploration prospects on this ultra deep shelf acreage position. For additional information regarding the risks associated with the SOO approval from the MMS, see "Risk Factors" included in Item 1A. of this Form 10-K.

Oil and Gas Activities.

Ultra-deep Exploration Activities. In February 2010, the Davy Jones discovery well on South Marsh Island Block 230 was drilled to a total depth of 29,000 feet. As reported in January 2010, we logged 200 net feet of pay in multiple Eocene/Paleocene (Wilcox) sands in the well. We are preparing to set a production liner and plan to temporarily abandon the well until completion equipment is available. We and our partners have initiated studies on the design for the completion of the well. Because of the pressures and temperatures encountered down hole, certain specialty completion equipment is expected to be required to produce the well. Because Davy Jones is located in shallow water near existing infrastructure, the lead times for commencing production are not expected to be as long or expensive as development would be in the deepwater Gulf of Mexico. We are the operator of the Davy Jones discovery well, have funded 25.7 percent of the exploratory costs and hold a 32.7 percent working interest and 25.9 percent net revenue interest. Our investment in Davy Jones totaled $21.2 million at December 31, 2009.

Once Davy Jones has been temporarily abandoned, we plan to move the rig to the Davy Jones offset appraisal location, which is located on South Marsh Island Block 234, two and a half miles southwest of the discovery well. The offset appraisal well (Davy Jones #2) has a proposed total depth of 29,950 feet and is expected to test similar sections up-dip to the discovery well.

In addition to Davy Jones, we have identified approximately 15 additional ultra-deep prospects (including prospects where we do not currently own rights to explore), which target Eocene/Paleocene or Miocene objectives below the salt weld. Our ultra-deep drilling plans in 2010 include the Blackbeard East and Lafitte wells. Future plans also include the John Paul Jones prospect, which is an Eocene/Paleocene test located on Louisiana State Lease 340, north of Davy Jones. The Blackbeard East well, which is located in 80 feet of water on South Timbalier Block 144, commenced drilling on March 8, 2010 and is currently drilling below 1,000 feet. The well has a proposed total depth of 29,950 feet and will target Middle and Deep Miocene objectives seen below 30,000 feet in Blackbeard West, nine miles away. Our partners in the Blackbeard East well include Plains Exploration & Production Company, Energy XXI, and W.A. "Tex" Moncrief, Jr. The Lafitte well, located at Eugene Island Block 223 in 140 feet of water, is expected to commence drilling in the third quarter of 2010. Like Blackbeard East, Lafitte will target Middle and Deep Miocene objectives.

We believe the information gained from the Blackbeard East and Lafitte wells will enable us to consider the priorities for future operations at Blackbeard West. Our investment in the Blackbeard West well totaled $31.6 million at December 31, 2009.

Deep Gas Exploration Activities. The Blueberry Hill offset appraisal well on Louisiana State Lease 340 commenced on November 8, 2009 and is currently drilling below 22,000 feet true vertical depth (TVD) (22,400 measured depth). The well is permitted to 22,550 feet TVD (23,000 measured depth) and drilling continues to evaluate deeper potential. We own a 42.9 percent working interest and a 29.7 percent net revenue interest in this well. Our investment in Blueberry Hill totaled $53.5 million at December 31, 2009, $6.7 million of which was incurred on the offset appraisal well currently in progress. If drilling results at the Blueberry Hill prospect are not sufficiently successful, our investment in Blueberry Hill could be subject to potential impairment. In addition, see "Risk Factors" in Item 1A. of this Form 10-K for discussion of the possibility of additional write-downs of capitalized costs of our oil and gas properties resulting from declining oil and natural gas prices.

The Hurricane Deep sidetrack well on South Marsh Island Block 217 commenced drilling on November 17, 2009 and had a proposed total depth of 21,750 feet. In February 2010, the operator encountered an underground flow in the well at approximately 18,450 feet. Attempts to contain the underground flow were unsuccessful and efforts are underway to abandon the wellbore. We are working to determine the timing of the re-drill. We expect the new well to have a proposed total depth of 21,750 feet and our 25 percent working interest share of the costs to drill to 18,450 feet to be covered under our insurance program. Our investment in Hurricane Deep totaled $16.5 million at December 31, 2009, including $3.1 million on sidetrack operations that commenced in 2009.

Our deep gas plans in 2010 also include the Boudin and Platte prospects. Boudin is located in 20 feet of water on Eugene Island Block 26. The well, which is expected to commence drilling in the second quarter, has a proposed total depth of 23,500 feet and will test Miocene objectives above the salt weld. Platte is located in Vermillion Parish, Louisiana. The well has a proposed total depth of 18,700 feet.

Production. We expect production to average approximately 190 MMcfe/d in the first quarter of 2010 and 180 MMcfe/d for the year. Our first quarter estimate is below our previous publicly reported estimate of 200 MMcfe/d because of unplanned downtime at certain fields, weather related issues and performance. Our estimated production rates are dependent on the timing and success of development drilling, planned recompletions, production performance and other factors.

Capital Expenditures. Capital expenditures are expected to approximate $260 million in 2010, including $180 million in exploration and $80 million in development spending. Our capital expenditure estimate is higher than our January 2010 estimate because of rig commitments entered into in February 2010, allowing us to accelerate start dates on certain prospects. Capital spending will continue to be driven by opportunities and will be managed based on available cash and cash flows, including potential participation by new partners in projects.

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.

	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Productive	1	0.250	2	0.500	4	1.150
Dry	4	1.417	3	1.095	1	0.150
In-progress [a]	6 [b]	2.013	7	2.188	5	1.673
Total	11	3.680	12	3.783	10	2.973
Development						
Productive	-	-	3	1.000	-	-
Dry	-	-	1	0.500	1	0.250
In-progress [c]	3	1.520	2	1.091	2	1.091
Total	3	1.520	6	2.591	3	1.341

a. Includes our 0.500 net interest in the JB Mountain Deep well and our 0.184 net interest in the Mound Point South well. These wells have been temporarily abandoned.
b. Includes our 0.327 net interest in the Davy Jones well which was announced as a discovery in early 2010.
c. Includes our 0.541 net interest in the Mound Point Offset No. 2 well and 0.550 net interest in the JB Mountain No. 3, in which we retain reversionary rights. These wells have been temporarily abandoned.

Productive Well Interests. The following table shows our interest in productive oil and natural gas wells as of December 31, 2009. 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	171	77.3	112	62.4
Onshore	18	6.4	3	1.7
Total	189	83.7	115	64.1

Exploration Agreements. In 2009, we entered into an agreement with W.A. "Tex" Moncrief Jr. (Moncrief) to participate in our ultra-deep drilling program. Moncrief agreed to fund drilling and production operations on a promoted basis to explore and develop targets below 25,000 feet (ultra-deep prospects). We and two of our partners assigned 10 percent of the group's collective working interest in Davy Jones to Moncrief. Moncrief may also participate for 10 percent of the collective interests of these parties in future ultra-deep wells.

Also in 2009, we entered into an arrangement with a private partner allowing that partner to participate in certain of our ongoing exploration and development activities. The private partner's initial funding commitment was $30 million. Additional commitments, if any, for the partner's participation and funding of future joint projects beyond the initial $30 million committed investment are at the discretion of the private partner.

MAIN PASS ENERGY HUB™ PROJECT

Our long-term business objectives may include the pursuit of multifaceted energy services development of the MPEH™, including the potential development of a liquefied natural gas (LNG) re-gasification and storage facility through Freeport Energy. The MPEH™ project is located at our Main Pass facilities located offshore in the Gulf of Mexico, 38 miles east of Venice, Louisiana.

The Maritime Administration (MARAD) approved our license application for the MPEH™ project in 2007, 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.

Prior to commencing construction of the MPEH™ facilities, we would be required to enter into commercial arrangements that would enable us to finance these costs. Commercialization of the project has been adversely affected by increased domestic supplies of natural gas, excess LNG re-gasification capacity and general market conditions. The ultimate outcome of our efforts to enter into commercial arrangements on reasonable terms to develop the MPEH™ project and obtain additional financing is subject to various uncertainties, many of which are beyond our control. For additional information on these and other risks, including without limitation, 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 as a result of related industry variables. We generally sell our crude oil and condensate one month at a time at then prevailing market prices. Oil and natural gas prices have fluctuated significantly over the past two years and we are unable to predict the future trend of oil and gas prices. We have entered, and may continue to enter into transactions that fix the future prices for portions of our 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. Among other things, the federal and state level regulation of our operations mandate that operators obtain permits to drill wells and to meet bonding and insurance requirements in order to drill, own or operate wells. These 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, 2009, we have interests in 189 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. 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 currently satisfying 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 for a prolonged duration would likely 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 (RCRA) 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 RCRA exemption that encompasses wastes directly associated with crude oil and gas production and the "petroleum exclusion" of CERCLA, 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 future capital expenditures 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. 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. As a result, we believe that we are in compliance with the Oil Pollution Act.

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, 2009, we had a total of 121 employees located at our New Orleans, Louisiana headquarters and our Houston, Texas and Lafayette, Louisiana offices. These employees are primarily devoted to production, regulatory, engineering, land, geological and various administrative functions. None of our employees are represented by any union or covered by a collective bargaining agreement, and we believe our relations with our employees are satisfactory.

Additionally, numerous services necessary for our business and operations, including certain executive, technical, administrative, accounting, financial, tax and other services, are 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.

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.

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 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, including, without limitation: statements regarding our financial plans; our indebtedness; our acquisition strategies; our exploration and development plans and related costs; the creditworthiness of our customers; agreements with third parties; losses from our operations; our ability to satisfy our reclamation, indemnification and environmental obligations; anticipated flow rates of producing and new wells; drilling potential and results; access to capital to fund our drilling activities; 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; our ability to hold current or future lease acreage rights; evaluating significant prospects; failure of our partners to fulfill their commitments; accounting methods we use to record our exploration results; and compliance with environmental regulations.

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, without limitation, the following:

Risks Relating to Financial Matters

If we are unable to generate sufficient cash to service and repay our debt or if there is a prolonged period of economic recovery from the global recession, our operating results, financial condition and ability to fully realize our business plan could be adversely affected.

The business of exploring for, developing and producing oil and natural gas is dependent upon, and affected by, demand for these resources, which in turn is affected by worldwide and national economic conditions. The widely reported global recession and continuing concerns that there could be a prolonged period of economic recovery have contributed to significant volatility in energy prices, reflecting the lack of sustained periods of higher global demand for oil and natural gas. These conditions, together with continued uncertainty regarding the stability of the global financial markets may, if unabated for an extended period, have potentially adverse consequences to our business and operations.

As of December 31, 2009 our outstanding debt totaled $374.7 million, including $300 million of our 11.875% Senior Notes due November 15, 2014 and $74.7 million of our 5 ¼% Senior Notes due October 6, 2011 as further described in Note 6. We must generate sufficient amounts of cash to service and repay our debt and to conduct our planned exploration and development activities. The inability to service, repay or refinance our indebtedness when due would have a negative impact on our financial condition and results of operations.

Agreements governing our indebtedness may limit our ability to respond to opportunities as they arise or execute our capital spending and related initiatives.

The terms of our amended and restated credit facility and other financing agreements governing our indebtedness restrict our ability to incur additional debt. Additionally, because the availability under our credit facility is subject to a borrowing base determined by the estimated future cash flows from our oil and natural gas reserves, a decline in the pricing for these commodities may result in a reduction in our borrowing base, which reduction could be significant, and as a result, would reduce the capital available to us.

If future debt financing is not available to us when required (as a result of limited access to the credit markets or otherwise), or is not available on acceptable terms, we may be unable to invest needed capital for our drilling and exploration activities, take advantage of business opportunities, respond to competitive pressures or refinance maturing debt, or be forced to sell some of our assets on an untimely basis or under unfavorable terms, any of which could have a material adverse effect on our operating results and financial condition.

The credit facility contains covenants and other restrictions customary for oil and gas borrowing base credit facilities, including limitations on debt, liens, dividends, voluntary redemptions of debt, investments, asset sales and transactions with affiliates. In addition, the credit facility requires that we maintain certain financial tests, including a leverage test (Total Debt to EBITDAX, as those terms are defined in the facility, for the preceding four quarters) and a secured leverage test (First Lien Debt to EBITDAX, as those terms are defined in the facility, for the preceding four quarters), and a current ratio test (current assets to current liabilities, subject to certain adjustments as of the end of the quarter).

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

During 2009, the continued decline in the market price for oil and natural gas coupled with certain other operational factors triggered impairment assessments that ultimately resulted in impairment charges to reduce the carrying values of several properties. Additional write-downs of the capitalized costs of individual oil and natural gas properties may occur if oil and natural gas prices further decline 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 write-down could adversely affect our results of operations and financial condition and the trading prices of our securities.

We use the successful efforts accounting method which requires all property acquisition costs and costs of exploratory and development wells to be capitalized when incurred, pending the determination of whether proved reserves are discovered. Additionally, 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.

If the capitalized costs of our oil and natural gas properties, on a field-by-field basis exceed the estimated future net cash flows of that field, we record impairment charges to reduce the capitalized costs of each such field to our estimate of the field's fair market value. We also record charges if proved reserves are not discovered at exploratory wells. These types of charges will reduce our earnings and stockholders' equity. 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.

Increasing domestic production and availability of unconventional sources of gas, including liquefied natural gas and gas extracted from shale formations, may in the future reduce the demand and price of the conventional natural gas we produce, and could have an adverse effect on our financial condition or results of operations.

Over the recent past, there has been an increase in the worldwide supply of unconventional gas, including liquefied natural gas (LNG) and gas extracted from shale formations utilizing advances in techniques for horizontal drilling and the fracturing of rock formations. While production of gas from unconventional sources is a relatively small portion of current North American gas production, it is expected to grow in the future.

As described more fully in Items 7. and 7A. "Management's Discussion and Analysis of Financial Condition and Results of Operation and Quantitative and Qualitative Disclosures About Market Risk," our production volume for 2009 is comprised of approximately 75 percent natural gas and our revenues are generally more sensitive to changes in the market price of natural gas than to changes in the market price of oil. As a result, any significant or prolonged increase in the domestic or worldwide supply of unconventional gas may result in a reduction in and price of the natural gas we produce, which could have an adverse effect on our financial position and results of operations.

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. Additionally, economic conditions and the price of oil and natural gas may, among other things, impair our ability to timely collect our receivables from these parties, result in downgrades to the credit ratings of our customers or other third parties that do business with us, or have other adverse consequences. While we sell oil and natural gas to third parties that we believe are reasonable credit risks, there is no guarantee, especially in light of these factors, that the risk associated with the creditworthiness of these parties will not increase.

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, and any financial difficulties encountered by these parties could also have an adverse affect on the exploration and development of our prospects.

We currently have agreements with third parties to support the funding of the exploration and development of certain of our properties and we may seek to enter into additional farm-out or similar arrangements with other companies in the future.

Our ownership interest in prospects subject to farm-out or other exploration arrangements revert to us only upon the achievement of a specified production threshold or the receipt by our partners and co-ventures of specified net production proceeds. Consequently, even if exploration and development of our prospects is successful, we cannot give assurance 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.

Additionally, our ability to enter into future beneficial relationships with third parties for our exploration and production activities may be limited, and as a result, may have an adverse effect on our current operational strategy and related business initiatives. Our farm-out partners and working interest co-owners may also 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. The degree to which these and other factors may adversely impact our partners and third-party operators (and the extent of any associated affect on us) is uncertain.

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 securities and our ability to raise additional capital, especially in the current marketplace.

Our losses from continuing operations were $204.9 million in 2009, $211.2 million in 2008 and $63.6 million in 2007. No assurance can be given that we will achieve profitability or positive cash flows from our operations in the future, especially given the current state of the credit markets and pricing for oil and natural gas. Our failure to achieve profitability in the future could adversely affect the trading price of our securities and our ability to raise additional capital.

We are responsible for reclamation, environmental indemnification and other obligations associated with our oil and gas properties and our former sulphur operations.

As of December 31, 2009, we had accrued $428.7 million relating to reclamation liabilities with respect to our oil and gas 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 Katrina, Rita and Ike. The scope and cost of these obligations may ultimately be materially greater than currently estimated.

As of December 31, 2009, we had $11.2 million relating to accrued reclamation liabilities with respect to our discontinued sulphur operations at Main Pass and $16.3 million relating to accrued reclamation liabilities with respect to our other discontinued sulphur operations, including $14.9 million for the Port Sulphur facilities. We are conducting the initial phase of 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.

In addition, we are responsible for indemnification obligations related to the former sulphur operations previously engaged in by us and our predecessor companies. We have also 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 Exploration Company (Newfield) from certain potential obligations, including environmental obligations relating to our 2007 oil and gas property acquisition. The scope and cost of these obligations may ultimately be materially greater than estimated at the time such indemnifications were granted and the related obligations were assumed. Our liabilities with respect to those obligations could adversely affect our operations and liquidity.

Risks Relating to our Operations

The high-rate production characteristics of our Gulf of Mexico properties 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 give assurance 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 be depleted 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 within a relatively short time frame. There can be no assurance that we will be able to replenish our reserves at attractive prices or within a suitable timeframe.

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.

We incurred $138.0 million in capital expenditures in 2009. We expect that our capital expenditures during 2010 will total approximately $260 million, including $180 million for costs associated with exploration opportunities and $80 million for anticipated development costs. These expenditures could fluctuate depending on the success of our drilling efforts and market conditions. 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 consider the availability of raising additional capital through future equity or debt transactions to continue our drilling activities and other project developments.

In the near-term, we plan to continue to pursue the drilling of our exploration prospects, although we have and will continue to adjust our drilling plan and capital expenditures as necessary. However, without adequate capital resources, our drilling and other activities may be limited and our business, financial condition and results of operations may suffer.

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:

- continued economic uncertainty in light of the current state of the global financial and credit markets;
- 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 anticipate that any of our near-term exploration and development activities will take place on deep and ultra-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 $10-$50 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 $100 million per well. We cannot assure you that we will have, or be able to obtain, sufficient capital to pursue these expenditures or that our oil and natural gas exploration activities, either on the deep shelf or elsewhere, will be commercially successful.

Our Davy Jones ultra-deep prospect has not yet been fully evaluated, and the ultimate impact of this potentially significant discovery will depend on, among other things, the volume of recoverable resources from the Davy Jones location and our ability to fund its commercial development through internally generated cash or third party funding.

In January 2010 we announced a potentially significant discovery at our Davy Jones ultra-deep prospect, with preliminary results indicating that certain hydrocarbon bearing sands may be of exceptional quality. However, flow testing is required to confirm the ultimate hydrocarbon flow rates from the separate zones within this prospect. While we are working to complete the flow test of this site as quickly as possible, the timing of completion and flow testing is dependent upon, among other things, the availability of necessary equipment required to handle the pressures and temperatures encountered in the well. As a result, there is no assurance as to when we will be able to complete flow testing of this prospect, or that once completed, our previously expressed expectations as to the size of the discovery in terms of recoverable product will be confirmed. There has been no production of oil and natural gas from ultra-deep reservoirs on the shelf of the Gulf of Mexico and such production may present technical challenges.

The commercial development and exploitation of the Davy Jones prospect will also require significant additional capital expenditures. As stated elsewhere in this Form 10-K, we have historically funded our operations and capital expenditures from, among other things, cash flow from operations and partnering arrangements with third parties. If we are unable to generate sufficient cash flow to appropriately fund the anticipated capital expenditures associated with the exploitation of this prospect, are unable to secure appropriate partners to share in these costs, or are otherwise unable to access capital in amounts sufficient to cover any projected shortfall, our ability to fully exploit this prospect may be adversely affected.

In the event we are unable to procure or maintain the suspension of operations (SOO) granted by the MMS with respect to certain of our ultra-deep gas play acreage, our ability to fully realize value associated with such acreage could be adversely affected.

Our interests in the offshore leases located in federal waters on the Gulf of Mexico's outer continental shelf are administered by the MMS and require compliance with MMS regulations and the Outer Continental Shelf Lands Act (OCSLA). Under the OCSLA, we are required to promptly and efficiently explore and develop any block or blocks to which these federal leases pertain within the initial term of such lease.

During the term of the initial term of a lease, our ability to drill, rework, or produce a particular well in paying quantities may, despite our diligent efforts, be delayed. In this case, we have the ability to request that the MMS extend the lease term beyond its scheduled expiration or termination. Provided our request in this regard is made timely and in accordance with regulatory guidelines, the MMS may grant or direct an SOO on the condition that we commit to undertake or complete certain specified actions during the extended term. While the decision of the MMS to grant or direct an SOO is made on a case-by-case basis, an SOO, if granted, is of limited duration.

At December 31, 2009, approximately 39,500 of the 142,300 (or approximately 30%) of the gross acres associated with our ultra-deep gas play were held under SOO's issued by the MMS effective through 2010. In addition, we have an additional 5,000 acres associated with our ultra-deep gas play which are scheduled to expire in 2010.

While it is not uncommon for companies in our industry to continue to operate leases under an SOO granted by the MMS, in the event (i) we fail to satisfy any obligations or conditions set forth in an SOO with respect to a particular lease, (ii) we are unable to procure an SOO from the MMS prior to the expiration of a primary lease term, (iii) the MMS denies a request to grant an additional SOO (or an extension of an existing SOO) with respect to a particular lease, or (iv) the MMS terminates an SOO previously granted based on a determination that either the circumstances justifying the SOO no longer exist or that the lease otherwise now warrants termination, our ability to exploit some of the potentially valuable acreage associated with our ultra-deep gas play (including certain acreage contiguous to our Davy Jones and Blackbeard discoveries) could be adversely affected.

A failure of our partners to fulfill their obligations or commitments to us could have an adverse effect on our operating results and financial condition.

We enter into contractual commitments related to our planned oil and gas exploration and development activities, including costs related to projects currently in progress, inventory purchase commitments and other exploration expenditures, some of which may be substantial. Additionally, a portion of our exploration program involves the sharing of certain costs associated with these expenditures with our partners.

At December 31, 2009, we had $278.9 million of contractual commitments, including $230.1 million of expenditures for drilling rig contract charges, portions of which we expect to share with our partners in our exploration program. A failure of our partners to fulfill their obligations or commitments to us, as a result of adverse consequences related to the current state of the financial markets or otherwise, would have an adverse effect on our operating results and financial condition.

The accounting methods we use to record our exploration results may result in losses.

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, among other things, these systems and facilities are unavailable, lack available capacity due to hurricane damage, or are (or become) affected by financial crisis and unpredictable pricing of oil and gas, we could be forced to shut in producing wells or delay or discontinue development plans. Additionally, federal and state regulation of oil and natural gas production and transportation, general economic conditions and changes in supply and demand could also 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 with complete accuracy. 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 different 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 average prices, calculated as the twelve-month average of the first day of the month prices as adjusted for location and quality differentials, and costs prevailing at December 31, 2009. There are no adjustments to normalize those costs based on variations over time either before or after that year. 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.

We cannot control the activities related to properties we do not operate.

Other companies operate several of the properties in which we have an interest. 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, financial resources, and ability to sustain operations through periods of distressed or adverse economic conditions;
- approval of operators or other participants in drilling wells; and
- selection of technology.

Hedging our production may expose us to various risks.

We may enter into hedging transactions to reduce our exposure to fluctuations in the market prices of oil and natural gas. These positions may also limit our potential profits if oil and natural gas prices were to rise significantly over the stated price in these contracts.

Hedging will expose us to risk of financial loss in some circumstances, including if:

- production is less than expected;
- the other party to the hedging 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.

Additionally, the ability of the financial institution counterparties to our hedging contracts to meet their obligations under such contracts may be adversely affected by market conditions. This may expose us to additional risks in realizing any benefits associated with our hedge positions.

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, including without limitation, the Oil Pollution Act of 1990 (which imposes a variety of legal requirements on "responsible parties" related to the prevention of oil spills). 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.

Additionally, new environmental laws or changes in existing laws (or their enforcement) may be enacted, and such new laws or changes may adversely affect the demand for our products or require significant additional expenditures by us to appropriately comply.

For example, recent scientific studies have suggested that emissions from the combustion of carbon-based fuels contribute to greenhouse effects and global climate change. In response to these findings, both federal and state governments have introduced or are contemplating regulatory changes regarding greenhouse gas emissions. The potential impacts of the passage of new climate change legislation or regulations to address, regulate or restrict the release of greenhouse gases are uncertain, and any such future laws could have an adverse effect on the general demand for the oil and natural gas that we produce or result in increased expenditures or additional operating expenditures.

Our operations could also 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 crude oil and natural gas exploration business is very competitive, and many of our competitors are larger and have greater financial strength.

The business of oil and natural gas exploration, development and production is very 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;

- adapt to fluctuations in the credit markets and periods of distressed or adverse economic conditions;
- 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 or catastrophic 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. Due to increased claims made by insureds for losses experienced in recent years from hurricanes in the Gulf of Mexico, and disruption in the domestic and global financial markets, the windstorm component of property damage insurance coverage has become more limited in scope and amount and the cost of coverage has increased. The reduced windstorm component of our property damage insurance coverage may increase our risks of casualty loss which could have a material adverse effect on our results of operations and financial condition. We no longer carry business interruption insurance as the increased level of hurricane activity in the Gulf of Mexico in recent years increased premiums to levels that are currently no longer cost effective. 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 operating in 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 the summer and early fall of each 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.

These exposures in the Gulf of Mexico 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 employment agreements 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.

We may not be able to obtain the necessary financing to complete the development of the Main Pass Energy Hub™ Project (MPEH™), and once operational, the MPEH™ project would be subject to certain risks.

Our long-term business objectives may include the pursuit of a multifaceted energy services development of the MPEH™ project. Should we decide to pursue this facility, we may not be able to obtain the necessary financing to complete its development and any such financing may be limited by restrictions contained in our existing financing agreements, or the financial, commodity and credit markets generally. Additionally, the MPEH™ project, once operational, would be subject to significant operating hazards and uninsured risks, one or more of which may create significant liabilities for us.

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. (Removed and Reserved).

Executive Officers of the Registrant

Listed below are the names and ages, as of March 1, 2010, 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	71	Co-Chairman of the Board
Richard C. Adkerson	63	Co-Chairman of the Board
Glenn A. Kleinert	67	President and Chief Executive Officer
C. Howard Murrish	69	Executive Vice President
Nancy D. Parmelee	58	Senior Vice President, Chief Financial Officer and Secretary
Kathleen L. Quirk	46	Senior Vice President and Treasurer

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 previously served 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 also founder of our predecessor company.

Richard C. Adkerson has served as our Co-Chairman of the Board since November 1998. He previously 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, and as President of FCX since January 2008 and previously from April 1997 to March 2007 and previously served as Chief Financial Officer of FCX from October 2000 to December 2003.

Glenn A. Kleinert has served as our President and Chief Executive Officer since February 2004. Previously he served as our Executive Vice President from May 2001 to February 2004. Mr. Kleinert has also served as President and Chief Operating Officer of MOXY since May 2001.

C. Howard Murrish has served as our Executive Vice President since November 1998. He previously served as Vice Chairman of the Board from May 2001 to February 2004. Mr. Murrish previously 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 our Senior Vice President and Chief Financial Officer since August 1999. She was appointed as Secretary of the company in January 2000. Ms. Parmelee has also served as Vice President of FCX since April 2003.

Kathleen L. Quirk has served as our Senior Vice President since April 2002 and Treasurer since January 2000. 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 previously served as Senior Vice President of FCX from December 2003 to March 2007. 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.

PART II

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

Our common stock is listed on the New York Stock Exchange (NYSE) under the symbol "MMR." Our Chief Executive Officer submitted the Annual CEO Certification to the NYSE as required under the

NYSE Listed Company rules. The 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.

	2009		2008	
	High	Low	High	Low
First Quarter	$12.35	$3.14	$18.62	$12.50
Second Quarter	7.71	4.26	35.52	17.01
Third Quarter	9.35	4.72	29.88	19.55
Fourth Quarter	9.78	6.77	23.26	7.39

As of February 26, 2010 there were 7,215 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. Currently, our debt agreements prohibit our payment of dividends on our common stock. At such time, if ever, that such restrictions are lifted, the Board of Directors have the sole discretion as to the timing and amount of any cash dividends.

Issuer Purchases of Equity Securities

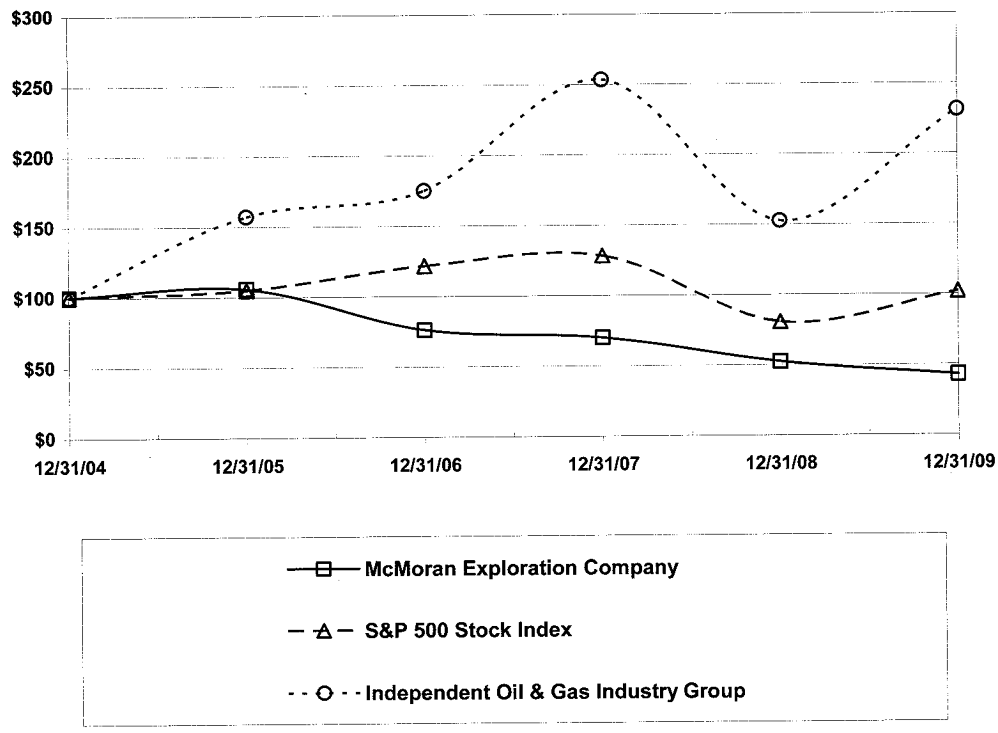
In 1999, our Board of Directors approved an open market share purchase program for up to 2.0 million shares of our common stock. In 2000, the Board of Directors authorized the purchase of up to an additional 0.5 million shares under the program. The program does not have an expiration date. No shares were purchased during the three years ending December 31, 2009. 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 an Independent Oil & Gas Industry Group and the S&P Stock Index from 2005 through 2009. This comparison assumes $100 invested on December 31, 2004 in (a) our common stock, (b) an Independent Oil & Gas Industry Group, and (c) the S&P 500 Stock Index.

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



	December 31,					
	2004	2005	2006	2007	2008	2009
McMoRan Exploration Co.	$100.00	$105.72	$ 76.04	$ 70.00	$ 52.41	$ 42.89
Independent Oil & Gas Industry Group	100.00	157.22	175.01	253.36	152.43	231.06
S&P 500 Stock Index	100.00	104.91	121.48	128.16	80.74	102.11

* 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, 2009. The historical information shown in the table below may not be indicative of our future results. You should read the information below together with Items 7. and 7A. "Management's Discussion and Analysis of Financial Condition and Results of Operations and 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.

	2009	2008	2007[a]	2006	2005
Financial Data	(Financial Data in Thousands, Except Per Share Amounts)				
Years Ended December 31:					
Revenues [b]	$ 435,435	$ 1,072,482	$ 481,167	$ 209,738	$ 130,127
Depreciation and amortization [c]	313,980	854,798	256,007	104,724	25,896
Exploration expenses	94,281	79,116	58,954	67,737	63,805
Main Pass Energy Hub™ costs [d]	1,615	6,047	9,754	10,714	9,749
Exploration expense reimbursement [e]	-	-	-	(10,979)	-
Litigation settlement [f]	-	-	-	(446)	12,830
Insurance recoveries [g]	(24,592)	(3,391)	(2,338)	(3,306)	(8,900)
Operating income (loss)	(168,434)	(155,234)	3,509	(32,567)	(22,373)
Interest expense, net	(42,943)	(50,890)	(66,366)	(10,203)	(15,282)
Loss from continuing operations	(204,889)	(211,198)	(63,561)	(44,716)	(31,470)
Income (loss) from discontinued operations [h]	(6,097)	(5,496)	3,827	(2,938)	(8,242)
Net loss applicable to common stock	(225,318)	(238,980)	(63,906)	(49,269)	(41,332)
Basic and diluted net loss per share of common stock:					
Continuing operations	$ (2.79)	$ (3.79)	$ (1.97)	$ (1.66)	$ (1.35)
Discontinued operations	(0.08)	(0.09)	0.11	(0.10)	(0.33)
Basic and diluted net loss per share	$ (2.87)	$ (3.88)	$ (1.86)	$ (1.76)	$ (1.68)
Average basic and diluted common shares outstanding	78,625	61,581	34,283	27,930	24,583
At December 31:					
Working capital (deficit)	$ 148,357	$ 3,601	$ (221,302)	$ (25,906)	$ 67,135
Property, plant and equipment, net	796,223	992,563	1,503,359	282,538	192,397
Total assets	1,248,882	1,330,282	1,715,288	408,677	407,636
Oil and gas reclamation obligations	428,711	421,201	294,737	25,876	26,484
Long-term debt	374,720	374,720	689,000	244,620	270,000
Stockholders' equity (deficit)	$ 265,808	$ 309,023	$ 372,229	$ (68,443)	$ (86,590)

a. Includes results from acquired oil and gas properties effective August 6, 2007 (Note 9).
b. Includes service revenues totaling $12.5 million in 2009, $13.7 million in 2008, $5.9 million in 2007, $13.0 million in 2006 and $12.0 million in 2005 (Note 1).
c. Includes impairment charges of $75.3 million in 2009, $332.6 million in 2008, $13.6 million in 2007 and $33.2 million in 2006. We did not record any impairment charges in 2005 (Note 4).
d. Reflects costs associated with pursuit of the licensing, design and financing plans related to the potential establishment of an energy hub, including an LNG terminal, at Main Pass Block 299 (Main Pass) in the Gulf of Mexico (Note 17).
e. Primarily reflects $19.0 million recognized upon inception of an exploration agreement in fourth quarter of 2006 offset by an $8.0 million payment to a private partner for relinquishing its exploration rights to certain prospects in connection with our entering into the new exploration agreement.

f. Reflects settlement of class action litigation case, net of insurance proceeds.
g. Reflects proceeds received in connection with our oil and gas property hurricane-related insurance claims (Note 4).
h. Amounts include charges for modification of previously estimated reclamation plans for remaining closed sulphur facilities at Port Sulphur, Louisiana and year-end reductions in the contractual liability associated with postretirement benefit costs relating to certain retired former sulphur employees (Notes 11 and 16).

	2009	2008	2007[a]	2006	2005
Operating Data					
Sales Volumes:					
Gas (thousand cubic feet, or Mcf)	50,081,900	59,886,900	38,994,000	14,545,600	7,938,000
Oil (barrels)	2,994,100	3,635,200	2,380,500	1,379,300	716,400
Plant products (Mcf equivalent)[b]	5,759,600	8,004,400	2,153,300	1,072,200	640,200
Average realization:					
Gas (per Mcf)	$ 4.22	$ 9.96	$ 7.01	$ 7.05	$ 9.24
Oil (per barrel)	60.22	104.00	76.55	60.55	53.82

a. Includes results from acquired oil and gas properties effective August 6, 2007 (Note 9).
b. Revenues from plant products (ethane, propane, butane, etc.) totaled $31.3 million in 2009, $83.3 million in 2008, $19.3 million in 2007, $9.6 million in 2006 and $5.0 million in 2005. One Mcf equivalent is determined using the ratio of six Mcf of natural gas to one barrel of crude oil, condensate or natural gas liquids.

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 capitalize on our geological, engineering and production strengths in these areas where we have more than 35 years of operating experience. We also believe that the scale of our operations in the Gulf of Mexico allows us to realize certain operating synergies and provides 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. Through our other wholly-owned subsidiary, Freeport-McMoRan Energy LLC (Freeport Energy), we may pursue our long-term business objectives to develop a multifaceted energy services project at the Main Pass Energy Hub™ (MPEH™). For additional information regarding our business and operations, see Items 1. and 2. entitled "Business and Properties" of this Form 10-K.

We intend to continue to focus on pursuing opportunities within our asset base and actively develop and exploit our recently announced Davy Jones ultra-deep discovery. Our actions during 2009 to preserve liquidity and manage our capital and operating needs, together with our equity financings, positions us to continue our active deep gas and ultra-deep gas exploration program. Capital spending will continue to be driven by opportunities and will be managed based on available cash and cash flow, including potential participation by new partners in projects. We may also seek additional financing for our future drilling and development activities.

Our technical and operational expertise is primarily in the Gulf of Mexico. We leverage our expertise by attempting to identify exploration opportunities with high potential. Our exploration strategy is focused on the "deep gas play," drilling to depths of between 15,000 to 25,000 feet in the shallow waters of the Gulf of Mexico and Gulf Coast area and on the "ultra-deep gas play" of depths below 25,000 feet. Deep gas prospects target large structures above the salt weld (i.e. listric fault) in the Deep Miocene. Ultra-deep prospects target objectives below the salt weld in the Miocene and older age sections that have been correlated to those productive sections seen in deepwater discoveries by other industry participants. A significant advantage to our exploration strategy is that the infrastructure to support the production and delivery of product is in most cases already in place and available. We believe this presents us with a material competitive advantage in bringing our discoveries on line and lowering related development costs. For additional information regarding our business strategy, see Items 1. and 2. "Business and Properties" of this Form 10-K.

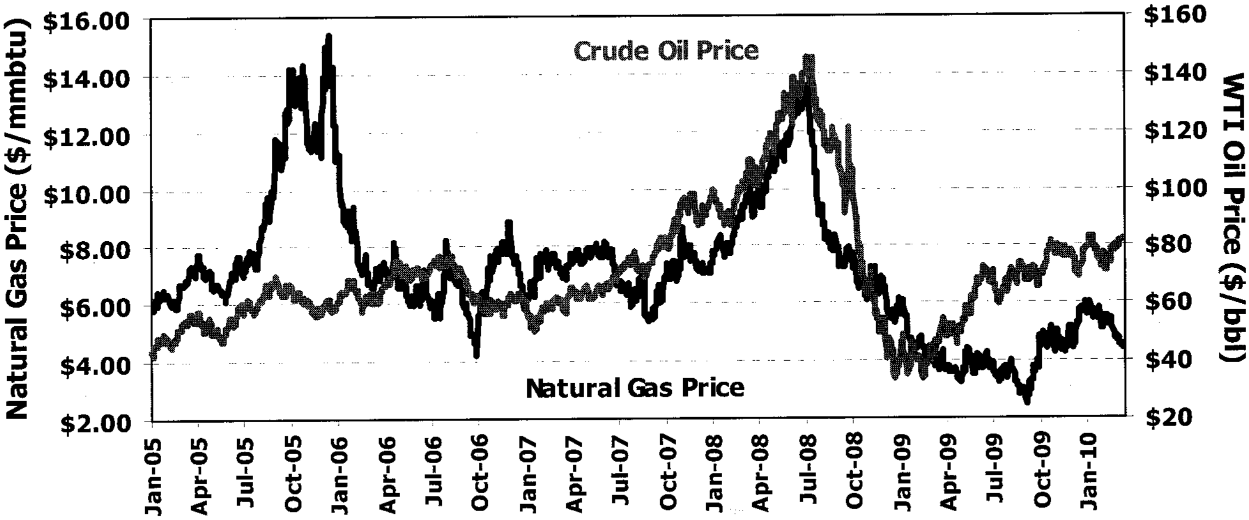
Implementing our business strategy will require significant expenditures during 2010 and beyond. During 2009, we spent $138.0 million on capital-related projects primarily associated with our exploration activities and subsequent development of the related discoveries. Our exploration, development and other capital expenditures for 2010 are expected to approximate $260 million, including $180 million in exploration costs and $80 million in development costs. Our capital expenditure estimate is higher than our January 2010 estimate because of rig commitments entered into in February 2010, which is allowing us to accelerate start dates on certain prospects. Capital spending will continue to be driven by opportunities and will be managed based on available cash and cash flows, including potential participation by new partners in projects. We also plan to spend approximately $100 million in 2010 to abandon and remove oil and gas structures from the Gulf of Mexico, a portion of which is associated with the removal of structures damaged during the 2005 and 2008 hurricane seasons. We expect to recover a substantial recovery of the costs associated with the 2008 hurricane losses from our insurance program. We plan to fund our exploration, development and reclamation activities with our cash on hand, operating cash flow, potential new partner arrangements or external financing sources.

We also continue to monitor the global financial and credit markets, as well as the fluctuations in oil and natural gas market prices, each of which have been widely publicized and may ultimately have a material affect on one or more facets of our business and overall business strategy. We will continue to evaluate and respond to any impact these conditions may have on our operations.

North American Natural Gas and Oil Market Environment

Our 2009 production volume is comprised of approximately 75 percent natural gas and 25 percent oil. As a result, our revenues are generally more sensitive to changes in the market price of natural gas than to changes in the market price of oil. Natural gas prices continue to be negatively affected by weak industrial demand and abundant supply. North American natural gas averaged $4.16 per MMbtu during 2009. The spot price for natural gas was $4.44 per MMbtu on March 11, 2010. The average price for crude oil was $61.95 per barrel in 2009 and the spot price was $82.11 per barrel on March 11, 2010. Future oil and natural gas prices are subject to change and these changes are not within our control. For additional information regarding risks associated with price fluctuations and supply of these commodities, see Item 1A. "Risk Factors" included in this Form 10-K.

Natural Gas and Crude Oil Prices - January 2005 - March 2010



OPERATIONAL ACTIVITIES

Oil and Gas Activities

For additional information regarding our current oil and gas activities, see "Oil and Gas Activities" in Items 1. and 2. "Business and Properties" of this Form 10-K.

Production Update

Our net production rates averaged 202 MMcfe/d during 2009 compared with 245 MMcfe/d during 2008 and 152 MMcfe/d in 2007. Fourth-quarter 2009 production averaged 209 MMcfe/d net to us, compared to 162 MMcfe/d in the fourth quarter of 2008.

Our fourth quarter 2008 production was adversely impacted by wells which were shut-in as a result of the September 2008 hurricanes in the Gulf of Mexico. Production in the fourth quarter of 2009 was slightly below publicly reported estimates of 215 MMcfe/d because of delays in the timing of recompletions originally planned for the fourth quarter that are now expected to be completed in 2010.

We expect production to average approximately 190 MMcfe/d in the first quarter of 2010 and 180 MMcfe/d for the year. Our first quarter estimate is below our previous publicly reported estimate of 200 MMcfe/d because of unplanned downtime at certain fields, weather related issues and performance. Our estimated production rates are dependent on the timing and success of development drilling, planned recompletions, production performance and other factors.

Acreage Position

For information regarding our acreage position, see Note 2 and "Properties — Acreage" in Items 1. and 2. "Business and Properties" of this Form 10-K.

RESULTS OF OPERATIONS

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

Our operating results changed substantially following the 2007 oil and gas property acquisition. Our operating results for 2009 and 2008 include the results from the acquired properties for those entire years. Our operating results for 2007 include the results from the acquired properties beginning on August 6, 2007.

Our operating loss during 2009 totaled $168.4 million which reflects (a) $75.3 million in impairment charges to reduce net carrying values to fair value for certain fields primarily related to the declines in market prices for oil and natural gas during 2009 and certain other operational factors that had a negative impact on reserve recoverability; (b) $61.5 million of non-productive exploratory drilling and related costs; (c) $24.6 million of insurance recoveries (gains) received as partial payments for insured losses related to the September 2008 hurricanes in the Gulf of Mexico; and (d) aggregated realized and unrealized gains of $17.4 million associated with the cash settlement and mark-to-market adjustment of the fair values of our oil and gas derivative contracts.

Our operating loss during 2008 totaled $155.2 million which reflects (a) $310.7 million in impairment charges to reduce net carrying values to fair value for certain fields related to the significant decline in the market prices for oil and natural gas during the fourth quarter of 2008; (b) $169.4 million of charges associated with damage to certain properties from the September 2008 hurricanes; (c) $38.9 million of non-productive exploratory drilling and related costs; and (d) aggregated realized and unrealized gains of $16.3 million associated with the cash settlement and mark-to-market adjustment of the fair values of our oil and gas derivative contracts.

Our 2007 operating income of $3.5 million reflects (a) $22.8 million of non-productive exploratory drilling and related costs; (b) an impairment charge of $13.6 million; and (c) an unrealized loss of $5.2 million associated with the mark-to-market adjustment of the fair values of our oil and gas derivative contracts.

Oil and Gas Operations – Year-to-Year Comparisons

Revenues. A summary of increases (decreases) in our oil and natural gas revenues as compared to the previous period follows (in thousands):

	2009	2008
Oil and natural gas revenues – prior year period	$ 1,058,804	$ 475,250
Increase (decrease)		
Price realizations:		
Natural gas	(287,470)	42,029
Oil and condensate	(131,082)	37,709
Sales volumes:		
Natural gas	(97,658)	41,029
Oil and condensate	(66,674)	7,418
Properties acquired in 2007	-	441,418
Plant products revenue	(51,980)	13,850
Other	(964)	101
Oil and natural gas revenues - current year period	$ 422,976	$ 1,058,804

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, 2009.

Our oil and natural gas sales volumes totaled 73.8 Bcfe in 2009, 89.7 Bcfe in 2008 and 55.5 Bcfe in 2007. The decrease in volumes in 2009 primarily relates to fields that were shut-in in 2009 due to the 2008 hurricanes. The increase in 2008 reflects the additional production from our 2007 oil and gas property acquisition as well as additional production from our Flatrock field. Average realizations received for oil sold during 2009 decreased by 42 percent over amounts received in 2008, which increased 46 percent over amounts received in 2007. Average realizations for natural gas sold during 2009 decreased 58 percent from amounts received during 2008, while average realizations for natural gas increased 29 percent in 2008 from amounts received during 2007. The variations in realizations for natural gas and oil sold during these years are related to the record high commodity prices during the first half of 2008 and significant decline of these commodity prices later in 2008 and continuing through 2009.

Our 2009 revenues included $31.3 million of plant product sales associated with approximately 5.8 Bcf equivalents for products (ethane, propane, butane, etc.) recovered from the processing of our natural gas. The amounts of plant product sales totaled $83.3 million from 8.0 Bcf equivalents during 2008 and $19.3 million from 2.2 Bcf equivalents in 2007.

Our service revenues totaled $12.5 million in 2009, $13.7 million in 2008 and $5.9 million in 2007. The increased amounts in 2009 and 2008 reflects additional production and handling fees from the processing of third party production and reimbursements of standard industry overhead fees associated with the 2007 oil and gas property acquisition.

Production and delivery costs. The following table reflects our production and delivery costs for the years ended December 31, 2009, 2008 and 2007 (in millions, except per Mcfe amounts):

	2009	Per Mcfe	2008	Per Mcfe	2007	Per Mcfe
Lease operating expense	$115.9	$1.57	$133.6	$1.49	$ 69.8	$1.26
Workover costs	18.0	0.25	39.7	0.44	19.7	0.35
Hurricane related repairs	14.1	0.19	23.1	0.26	-	-
Insurance	23.9	0.32	22.6	0.25	23.2	0.42
Transportation, production taxes and other	21.1	0.29	39.5	0.44	9.4	0.17
Total production and delivery costs	$193.0	$2.62	$258.5	$2.88	$122.1	$2.20

Our lower lease operating expense in 2009 reflects decreased production, as well as the results of efforts to lower our operating costs given the significant decline in oil and natural gas prices during the year. Workover costs have decreased from the prior period due to the type and number of projects being completed in 2009. Our 2008 higher lease operating expense reflects increased production over 2007 primarily due to the 2007 oil and gas property acquisition. Hurricane related repairs related to work performed on wells in 2009 and 2008 related to the 2008 Hurricanes Gustav and Ike.

Our insurance rates and coverage terms associated with our June 2009-May 2010 insurance program renewal were less favorable to us than in prior years because of the impact that the 2008 hurricanes have had on coverage capacity and premium costs for operators in the Gulf of Mexico. Available windstorm coverage associated with our renewal was limited and costly. After assessing various alternatives, we elected to purchase insurance with significantly reduced coverage for "windstorm event" related risks in comparison to our previous insurance program. The total insurance premiums under the renewal program provide less coverage at similar costs to the previous program. Our 2008 insurance costs were comparable to 2007, which included the incremental insurance cost associated with coverage on the properties acquired in 2007. For additional information related to risks associated with our insurance coverage, see Item 1A. "Risk Factors" in this Form 10-K.

Transportation and production taxes decreased in 2009 primarily due to decreased production during 2009 resulting from wells that were shut-in following the 2008 hurricanes. The increased costs in 2008 compared to 2007 resulted from the increased production associated with the properties acquired in 2007.

Depletion, depreciation and amortization expense. The following table reflects the components of our depletion, depreciation and amortization expense for the years ended December 31, 2009, 2008 and 2007 (in millions, except per Mcfe amounts):

	2009	Per Mcfe	2008	Per Mcfe	2007	Per Mcfe
Depletion and depreciation expense	$205.5	$2.78	$357.5	$3.98	$228.5	$4.12
Accretion expense	33.2	0.45	164.8	1.84	13.9	0.25
Impairment charges/losses	75.3	1.02	332.5	3.71	13.6	0.25
Total depletion, depreciation and amortization expense	$314.0	$4.25	$854.8	$9.53	$256.0	$4.62

As described 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 decrease in our depletion and depreciation expense in 2009 from 2008 primarily reflects lower production rates in 2009 as well as the significant reduction in the carrying value of our proved oil and gas property costs resulting from impairment charges recorded in late 2008 and throughout 2009. The increase in our depletion and depreciation expense in 2008 over 2007 primarily reflects increased production from new discoveries and production from the 2007 oil and gas property acquisition.

We record accretion expense on our discounted reclamation obligations. In 2008 we recorded amounts to accretion expense totaling $124.4 million to reflect higher estimates and accelerated timing of future abandonment costs associated with hurricane damaged structures and wells. That, along with the impact of higher reclamation accretion from the properties acquired in 2007, primarily account for the variances in accretion expense when comparing such amounts among the years ended 2009, 2008 and 2007.

As further discussed 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.

Due to the decline in market prices for oil and natural gas and certain other operational factors that negatively impacted reserve recoverability, we recorded impairment charges of $75.3 million in 2009.

The significant decline in market prices in the fourth quarter of 2008 for oil and natural gas resulted in an impairment charges of $246.9 million related to certain producing properties as of December 31, 2008. We also recorded impairment charges totaling $44.9 million on two previously unevaluated wells (Mound Point South and JB Mountain Deep) after considering our then current drilling plans in the economic environment at that time.

Earlier in 2008, we also recorded impairment charges totaling $40.8 million relating to certain fields including the Ewing Banks 947 and South Marsh Island Block 49 wells which were significantly damaged by Hurricane Ike in the third quarter of that year.

In 2007, we recorded an impairment charge related to one field totaling $13.6 million.

As more fully identified in Item 1A. "Risk Factors" and elsewhere in this Form 10-K, a combination of any or all of these conditions described above including the factors that contributed to the recognition of significant impairment charges in 2009 and 2008, could require additional impairment charges to be recorded in future periods.

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

	Years Ended December 31,		
	2009	2008	2007
Geological and geophysical, including 3-D seismic purchases [a]	$ 26.8	$ 31.9	$ 29.9 [b]
Dry hole costs	61.5 [c]	38.9 [d]	22.8 [e]
Insurance and other	6.0	8.3	6.3
	$ 94.3	$ 79.1	$ 59.0

a. Includes compensation costs associated with stock-based awards totaling $6.6 million in 2009, $14.4 million in 2008 and $6.3 million in 2007.
b. Includes $13.0 million of seismic data purchases primarily associated with the exploration acreage acquired in the 2007 oil and gas property acquisition.
c. Includes nonproductive exploratory drilling and related costs primarily associated with the Ammazzo well ($25.4 million), the Tom Sauk well ($11.1 million), the Cordage well ($11.0 million), the Sherwood well ($6.3 million) and the Gladstone East well ($6.2 million).
d. Includes nonproductive exploratory drilling and related costs primarily associated with the Mound Point East well at Louisiana State Lease 340 ($16.0 million), the Northeast Belle Isle well ($9.5 million) and the Gladstone East well ($5.4 million) as well as approximately $8.0 million of nonproductive leasehold costs.
e. Primarily includes nonproductive exploratory drilling and related costs associated with the "Cas" well

at South Timbalier Block 70 ($21.6 million).

Other Financial Results
Operating

Our general and administrative expenses totaled $43.0 million in 2009, $49.0 million in 2008 and $28.0 million in 2007. We charged approximately $7.2 million of stock-based compensation costs to general and administrative expense during 2009 compared to $14.8 million in 2008 and $6.3 million in 2007. The decrease in stock-based compensation costs in 2009 and related increase in such costs from 2007 to 2008 is related to the timing of the valuation of the 2008 option grants, which occurred at a time when the price of our common stock exceeded $30 per share. The remaining increase in general and administrative expense in 2008 compared to 2007 reflects additional personnel associated with administering the oil and gas properties acquired in 2007.

In 2009, we recorded an aggregate $17.4 million gain associated with our oil and gas derivative contracts. In 2008 and 2007, we recorded an aggregate $16.3 million gain and $5.2 million loss, respectively, associated with our oil and gas derivative contracts (Note 7). The variances among these years resulted from changes in commodity prices and the resulting mark-to-market impact that such changes had with respect to our derivative contract positions during those years.

Hurricanes Gustav and Ike disrupted our Gulf of Mexico operations prior to making landfall on the Louisiana and Texas coasts on September 1, 2008 and September 13, 2008, respectively. There was no significant damage to our properties resulting from Hurricane Gustav. However, Hurricane Ike caused significant structural damage to several platforms in which we had an investment interest. Since the third quarter of 2008, we have recorded charges totaling in excess of $180 million related to incurred repair costs, property impairments and additional estimated reclamation costs associated with the damaged properties. While a portion of these costs has been funded to date, a significant amount of the remaining expenditures, particularly for asset retirement obligations, will be funded by us over the next several years. We expect to realize a substantial recovery in future periods under our insurance program for a large portion of these hurricane related costs, reimbursement for which will be received after damage-related expenditures are funded and related claims are approved. We received net insurance proceeds of $24.6 million in 2009, after satisfying our $50 million deductible, as partial payments associated with certain of our insured hurricane-related losses.

Our 2008 operating results included $3.4 million of insurance recoveries relating to our final Hurricane Katrina settlement. Our operating results in 2007 included insurance recoveries totaling $2.3 million related to our Hurricane Katrina property loss claims.

Non-Operating

Interest expense, net of capitalized interest, totaled $42.9 million in 2009, $50.9 million in 2008 and $66.4 million in 2007. We capitalized interest totaling $3.9 million in 2009, $5.0 million in 2008 and $6.3 million in 2007. The decrease in interest expense in 2009 and 2008 is associated with our debt reductions during 2008, the benefits of which provided reduced borrowing costs for all of 2009 and a portion of 2008. 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 $4.0 million in 2009, $(2.6) million in 2008 and $(0.7) million in 2007. Interest income for the three years ended December 31, 2009 totaled $0.7 million in 2009, $1.1 million in 2008 and $2.2 million in 2007. Other income in 2009 primarily related to a $2.7 million gain related to the settlement of a contingency associated with the 2007 oil and gas property acquisition (Note 9). Other expense in 2008 included $2.7 million of inducement payments related to our convertible senior notes (see "— Capital Resources and Liquidity—Convertible Senior Notes" below). Other expense in 2007 included the prepayment premium of $3.0 million to terminate our senior secured term loan partially offset by interest income.

Income tax benefit (expense) totaled $2.4 million in 2009 and $(2.5) million in 2008. We recorded no income tax benefit (expense) in 2007. On November 6, 2009 "The Worker, Homeownership, and Business Assistance Act of 2009" (the Act) was enacted. This legislation allows businesses with tax net operating losses (NOLs) from 2009 or 2008 to carry back those losses for an extended period of up to five years to recover prior period tax payments. The Act also provides for the suspension of the 90% limitation on the use of alternative minimum tax NOL deductions attributable to carry backs from these years for which an extended carry back period is elected. Our $2.4 million income tax benefit in 2009 primarily reflects the expected carry back of our 2009 tax NOL and refund of our 2008 federal alternative minimum tax.

As of December 31, 2009, we had approximately $728.5 million of NOLs ($485.1 million federal and $243.4 million state) available to offset future taxable income, subject to certain limitations. Federal tax regulations impose certain annual limitations on the utilization of NOLs from prior periods when a defined level of change in ownership of certain shareholders is exceeded. If a corporation has a statutorily defined change of ownership, its ability to use its existing NOLs could be limited by Section 382 of the Internal Revenue Code depending upon the level of future taxable income generated in a given year and other factors. We have determined that such a change of ownership has occurred, which, depending upon the amounts and timing of future taxable income generated, may limit our ability to use our existing NOLs to fully offset taxable income in future periods.

In February 2010, the Obama Administration released its Fiscal Year 2011 budget which includes proposals that, if legislated and enacted into law, would make significant changes to United States (U.S.) tax laws, including the elimination of certain important U.S. federal income tax incentives currently available to companies involved in oil and gas exploration, development and production. It is uncertain whether any of the proposed tax changes will actually be enacted or how soon any changes could become effective. The passage of any legislation requiring these or similar changes in U.S. federal income tax law could negatively impact our financial condition and results of operations.

Discontinued Operations

Our discontinued operations resulted in income (loss) of $(6.1) million in 2009, $(5.5) million in 2008 and $3.8 million in 2007. The results in 2009 include additional caretaking and environmental remediation charges of approximately $4.1 million and $1.9 million in reclamation, contingency and sulphur retiree costs. The 2008 results include $3.4 million in reclamation and contingency costs. The results in 2007 include the impact of $4.6 million of contractual liability reductions for sulphur retirees due to favorable healthcare claims experience and $4.2 million of insurance related gains resulting from the 2005 hurricane damage claims. The future estimated closure costs for our former terminal facilities at Port Sulphur, Louisiana approximate $14.9 million at December 31, 2009, the funds for which are expected to be expended over the next two years. Our discontinued operations' results are summarized in Note 11.

In connection with the June 2002 sale of assets, we 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 and successor companies, including reclamation and other potential environmental obligations. In addition, we 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, 2009, we paid approximately $0.2 million to settle certain claims related to these assumed liabilities.

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,		
	2009	2008	2007
Continuing operations			
Operating	$ 136.9	$ 629.7	$ 209.6
Investing	(138.0)	(239.2)	(1,195.2)
Financing	154.8	(295.5)	974.6
Discontinued operations			
Operating	$ (5.7)	$ (6.3)	$ (2.0)
Investing	-	-	-
Financing	-	-	-
Total cash flow			
Operating	$ 131.2	$ 623.4	$ 207.6
Investing	(138.0)	(239.2)	(1,195.2)
Financing	154.8	(295.5)	974.6

Comparison of Year-To-Year Cash Flow

Operating Cash Flow

Our 2009 operating cash flow decreased significantly from 2008 reflecting lower oil and gas revenues resulting from the significantly lower oil and natural gas prices in 2009 as well as decreased production due to shut-ins from the 2008 hurricanes. Our 2008 and 2007 operating cash flow reflected increased oil and gas revenues reflecting production from our 2007 oil and gas property acquisition reduced by increased working capital requirements.

Cash used in our discontinued operations in 2009, 2008 and 2007 primarily reflect caretaking, remediation and other closure costs associated with our Port Sulphur, Louisiana former sulphur terminal. We estimate that we will incur approximately $14.9 million of closure costs over the next two years with respect to currently planned closure activities (Note 11).

Investing Cash Flow

Our 2009 and 2008 investing cash flow reflect capital expenditures of $138.0 million and $236.4 million, respectively, representing our exploratory drilling and development costs. Our 2009 expenditures were reduced in comparison to 2008 reflecting management of capital spending in response to commodity price levels and financial market conditions.

Our investing cash flow in 2007 reflects the 2007 oil and gas property acquisition cost of $1.05 billion, net of purchase price adjustments, and capital expenditures of $153.2 million, representing our exploratory drilling and development costs. Our 2007 investing cash flow 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 (5¼% notes) on April 6, 2007 and October 6, 2007.

Financing Cash Flow

Our 2009 financing cash flow reflect net proceeds of $168.3 million from the sale of 15.5 million shares of our common stock and 86,250 shares of $1,000 par value 8% convertible perpetual preferred stock (8% preferred stock) (Note 8). We also paid $13.5 million in dividends on our 8% preferred stock and our 6¾% convertible preferred stock (6¾% preferred stock).

In 2008, we repaid $274.0 million in net borrowings under our credit facility and paid $2.7 million to induce conversion of $79.3 million of our convertible senior notes. We also paid $23.6 million in dividends on our preferred stock and inducement payments on the early conversion of approximately 990,000 shares of our 6¾% preferred stock.

Cash flow from our financing activities during 2007 primarily reflects the funding of the acquisition price for our 2007 oil and gas property acquisition. At closing, we borrowed $800 million under an interim bridge loan facility (bridge loan) and $394 million under our credit facility. In November 2007, we repaid the bridge loan following sales of shares of our 6¾% preferred stock and common stock, which resulted in net proceeds of $450.6 million, and the sale of $300 million of 11.875% senior notes (senior notes) due

2014. Costs associated with these financing transactions totaled $30.6 million. Total net borrowings under our credit facility totaled $245.3 million in 2007. Additionally, our 2007 cash flow from financing activities also reflects $10.4 million of proceeds from the exercise of stock based awards, including the exercise of warrants for 1.74 million shares (Note 4) and $1.1 million of preferred stock dividend payments. For more information regarding our financing transactions see "Variable Rate Senior Secured Revolving Credit Facility," "11.875% Senior Notes," "Convertible Senior Notes," and "Equity Offerings" below.

Variable Rate Senior Secured Revolving Credit Facility

Our credit facility matures in August 2012. The borrowing capacity was $175 million at December 31, 2009. We had no borrowings outstanding under the credit facility during the year ended December 31, 2009, and we did not borrow under the credit facility during 2009. A letter of credit in the amount of $100 million remains outstanding under the credit facility to support a portion of the reclamation obligations assumed in the 2007 oil and gas property acquisition (Note 9).

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

The credit facility contains covenants and other restrictions customary for oil and gas borrowing base credit facilities, including limitations on debt, liens, dividends, voluntary redemptions of debt, investments, asset sales and transactions with affiliates. In addition, the credit facility requires that we maintain certain financial tests, including a leverage test (Total Debt to EBITDAX, as those terms are defined in the facility, for the preceding four quarters) and a secured leverage test (First Lien Debt to EBITDAX, as those terms are defined in the facility, for the preceding four quarters), and a current ratio test (current assets to current liabilities, subject to certain adjustments as of the end of the quarter). We were in compliance with these covenants at December 31, 2009.

11.875% Senior Notes

On November 14, 2007, we completed the sale of $300 million of our 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 our common stock and 6¾% 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 19). We may redeem some or all of these notes at our 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 restrict our ability to pay certain cash dividends on common stock, repurchase or redeem common or preferred equity, prepay subordinated debt and make certain other investments.

Convertible Senior Notes

Our 5¼% notes due October 6, 2011 totaled $74.7 million at December 31, 2009. The 5¼% notes are convertible at the option of the holder at any time prior to maturity into shares of our common stock at a conversion price of $16.575 per share (Note 6). Since October 6, 2009, we have had 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 the notes prior to the redemption date, provided the closing price of our common stock exceeded 130 percent of the conversion price for at least 20 trading days in any consecutive 30-day trading period.

During 2008, we privately negotiated transactions to induce the conversion of $40.2 million of the 5¼% notes into approximately 2.4 million shares of our common stock. We paid an aggregate $1.7 million in cash to induce these conversions, which is reflected as non-operating expense in the consolidated statements of operations.

Our former 6% convertible senior notes matured on July 2, 2008 (6% notes). Prior to the conversion date, we privately negotiated transactions to induce the conversion of $39.1 million of the 6% notes into approximately 2.75 million shares of our common stock. We paid an aggregate of $1.0 million in cash to induce these conversions, which is reflected as non-operating expense in the consolidated statements of operations. Additionally, $61.7 million of the 6% notes were converted into approximately 4.3 million shares of our common stock in accordance with the terms of the 6% notes (including $43.5 million of the 6% notes converted into shares of common stock upon maturity on July 2, 2008).

Equity Offerings

In June 2009, we completed concurrent public offerings of 15.5 million shares of common stock at $5.75 per share and 86,250 shares of 8% preferred stock with an offering price of $1,000 per share (Note 8). The net proceeds from these offerings, after deducting the underwriters' discounts and other expenses, were approximately $168.3 million. We are using the net proceeds from the offerings for general corporate purposes, including funding of capital expenditures.

The 8% preferred stock is recorded at liquidation preference value ($1,000 per share) in the accompanying consolidated balance sheet. The first quarterly cash dividend was $11.78 per share (reflecting the partial quarter) and was paid on August 15, 2009, and subsequent quarterly dividend payments are $20.00 per share. The 8% preferred stock is convertible into an aggregate of 12.6 million shares of our common stock (equivalent to a conversion price of $6.8425 per share), subject to certain anti-dilution adjustments. Beginning June 15, 2014, we have the right to redeem shares of the 8% preferred stock by paying cash, our common stock or any combination thereof for $1,000 per share plus accumulated and unpaid dividends, but only if the trading price of our common stock has exceeded 130% of the initial conversion price for at least 20 trading days within a period of 30 consecutive trading days ending on the trading day before the date we give the redemption notice.

In February 2010, we privately negotiated the induced conversion of approximately 43,000 shares (49.99% of the total outstanding) of our 8% preferred stock with a liquidation preference of $43.1 million into approximately 6.3 million shares of our common stock (at a conversion rate equal to 146.1454 shares of common stock per share of 8% preferred stock). To induce the early conversions of these shares of 8% preferred stock, we paid an aggregate of $8.0 million in cash to the holders of these shares. These holders also received the scheduled dividend on the 8% preferred stock on February 15, 2010. Preferred annual dividend savings following these transactions approximate $3.4 million. Following these transactions, we have approximately 43,000 shares of our 8% preferred stock outstanding.

In November 2007, we completed a public offering of 16.89 million shares of our common stock at $12.40 per share and a concurrent public offering of 2.59 million shares of our 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 2007 oil and gas property acquisition.

Each share of the 6¾% preferred stock has a par value of $100 and holders are entitled to receive quarterly cash dividends at a 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 was convertible into between 17.4 million and 20.9 million shares of our common stock depending on the price of our common stock, subject to anti-dilution adjustments. The 6¾% preferred stock will automatically convert into shares of our common stock on November 15, 2010. Holders of the 6¾% preferred stock may elect at any time before November 15, 2010 to convert their shares at a conversion rate equal to 6.7204 shares of common stock for each share of 6¾% preferred stock.

In 2008, we privately negotiated the induced conversion of approximately 990,000 shares of our 6¾% preferred stock (approximately 40% of the original issuance), with a liquidation preference of approximately $99 million, into approximately 6.7 million shares of our common stock (based on the minimum conversion rate of 6.7204 shares of common stock for each share of 6¾% preferred stock). We paid an aggregate $7.4 million in cash to the holders of these shares to induce the conversion of this 6¾% preferred stock, which is recorded as a $7.4 million charge to preferred dividends in the third quarter of 2008. Preferred dividend payment savings related to this transaction approximate $15 million through the November 2010 mandatory conversion date of the securities. Following this transaction, the remaining outstanding 6¾% preferred stock is convertible into between 10.7 million and 12.8 million shares of our common stock depending on the price of our common stock, subject to anti-dilution adjustments.

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. 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 their shares of 5% 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 ($118.5 million at December 31, 2009), we have other contractual obligations and commitments that will require payments in 2010 and beyond.

The table below summarizes the principal maturities and interest payments associated with our 5¼% notes and senior notes, our expected payments for retiree medical costs (Notes 12 and 16), our current exploration and development commitments and our remaining minimum annual lease payments as of December 31, 2009 (in millions):

	Debt and Convertible Securities [a]	Interest Payments[b]	Retirement Benefits[c]	Oil & Gas Obligations[d]	Lease Payments[e]	Total
2010	$ -	$ 45.4	$ 1.3	$ 174.9	$ 2.3	$ 223.9
2011	74.7	45.4	1.2	70.7	2.3	194.3
2012	-	37.9	1.2	18.3	2.3	59.7
2013	-	35.6	1.2	5.0	2.2	44.0
2014	300.0	31.2	1.1	5.0	1.2	338.5
Thereafter	-	-	4.9	5.0	-	9.9
Total	$ 374.7	$ 195.5	$ 10.9	$ 278.9	$ 10.3	$ 870.3

a. Amounts due upon maturity subject to change based on future conversions by the holders of the securities.
b. Reflects interest and unused commitment fees on the debt balances as of December 31, 2009. Because we did not have any amounts outstanding under our credit facility as of December 31, 2009, we assumed a zero percent effective annual interest rate on our credit facility and a 2.98 percent and 0.50 percent interest rate on outstanding letters of credit ($100 million) and unused commitment fee, respectively. Interest on the convertible senior notes is fixed.
c. Includes anticipated payments under our employee retirement health care plan through 2019 (Note 12) and our future reimbursements associated with the contractual liability covering certain of our former sulphur retirees' medical costs (Note 16).
d. These oil & gas obligations primarily reflect our net working interest share of authorized exploration and development project costs at December 31, 2009 (see below for total estimated exploration and development expenditures for 2010). Included in these amounts is $230.1 million of expenditures for drilling rig contract charges, portions of which we expect to share with our partners in our exploration program. Also includes escrow payments to support the funding requirements related to the 2007 oil and gas acquisition property reclamation obligations (Note 16).
e. Amount primarily reflects leases for office space in two buildings in Houston, Texas, which terminate in April 2014 and July 2014, respectively, and office space in Lafayette, Louisiana which terminates in November 2012.

The table above excludes amounts associated with our oil and gas and sulphur property asset retirement obligations. As of December 31, 2009, approximately $456.2 million of such obligations were recorded as liabilities, $115.1 million of which was reflected as current liabilities (Note 16). Additionally, McMoRan is not a party to any off-balance sheet arrangements that require disclosure in the table above.

We are currently meeting our MMS financial obligations relating to the future abandonment of our Main Pass sulphur 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.

We continue to closely monitor global financial and capital markets, as well as fluctuations in the market prices for oil and natural gas. Our planned 2010 exploration, development and other capital expenditures approximate $260 million, including approximately $180 million in exploration costs and $80 million in development costs. We also expect to spend approximately $100 million in 2010 to abandon and remove oil and gas structures from the Gulf of Mexico, a portion of which is associated with the removal of structures damaged during the 2005 and 2008 hurricane seasons. Our capital spending will continue to be driven by opportunities and will be managed based on our available cash and cash flows, including potential participation by new partners in projects. Our expected level of capital expenditures is 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.

MAIN PASS ENERGY HUB™ PROJECT

Our long-term business objectives may include the pursuit of multifaceted energy services development of the MPEH™ project, including the potential development of a liquefied natural gas (LNG) regasification and storage facility through Freeport Energy. As of December 31, 2009, we have incurred approximately $51.8 million of cash costs associated with our pursuit of establishment of MPEH™, including $1.2 million in 2009. As of December 31, 2009, we have recognized a liability of $11.2 million relating to the future reclamation of the MPEH™ related facilities. The actual amount and 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. We will require commercial arrangements for the MPEH ™ project to obtain financing, which may be in the form of additional debt and/or equity transactions. The ultimate outcome of our efforts to enter into commercial arrangements on reasonable terms to develop the MPEH™ project and obtain additional financing is subject to various uncertainties, many of which are beyond our control. Commercialization of the project has been adversely affected by increased domestic supplies of natural gas, excess LNG re-gasification capacity and general market conditions.

For additional information regarding the MPEH™ project and risks associated therewith, including preliminary capital expenditure estimates, see Item 1A. "Risk Factors" included in this Form 10-K. Also see Note 17 regarding information about transactions that may reduce our future ownership interest in the MPEH™ project.

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 dismantling 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. We are 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. Our sulphur reclamation obligations are associated with our former sulphur mining operations.

Among our oil and gas 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, Rita and Ike. We record the fair value of our estimated asset retirement obligations in the period such obligations are incurred, rather than accruing the obligations as the related reserves are produced.

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 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 ranging from 10-20 percent, which reflects an estimated premium that a third party would expect for assuming an obligation for a fixed price on a current basis when that obligation is to be settled in the future. 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; (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; (3) changes in the reclamation costs based on revised estimates of future reclamation work to be performed; and (4) 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 6.9 percent to 13.1 percent at December 31, 2009 and 8.5 percent to 13.1 percent at December 31, 2008.

The following table summarizes the estimates of our reclamation obligations at December 31, 2009 and 2008 (in thousands):

	Oil and Gas		Sulphur	
	2009	2008	2009	2008
Undiscounted cost estimates	$ 538,778	$ 642,155	$ 43,418	$ 42,557
Discounted cost estimates	$ 428,711	$ 421,201	$ 27,452	$ 23,003

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	$ 19.2	$ (17.9)	$ 2.6	$ (2.6)
Discounted	6.4	(13.2)	1.5	(5.3)
Sulphur reclamation obligations:				
Undiscounted	6.2	(5.0)	0.3	(0.3)
Discounted	1.2	(1.0)	-	-

Depletion, Depreciation and Amortization, Including Impairment Charges. 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, 2009, we estimate that our depletion, depreciation and amortization expense for 2009 would have decreased by approximately $20.2 million, while a 10 percent decrease in estimated proved reserves for each property would have resulted in an approximate $20.8 million increase in our depletion, depreciation and amortization expense for 2009. 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 Notes 1 and 4, 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.

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 2010, excluding the sales quantity amounts associated with our current oil and gas derivative contract amounts (see below), a change of $1.00 per Mcf in the average realized price would have an approximate $50 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 $15 million net impact on our revenues and pre-tax operating results. Based on our currently projected sales volumes for 2010, 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 $30 million and our pre-tax operating results by approximately $15 million while a 10 percent fluctuation in our oil sales volumes would have an approximate $20 million impact on revenues and an approximate $15 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, shut-in or recompletion activities on any of our oil and gas properties or on third-party owned pipelines or facilities and the state of the financial and commodity markets. 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 and commodity price fluctuations, see Item 1A. "Risk Factors" of this Form 10-K.

We do not have any amounts outstanding under our credit facility; however, if we did, the 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.

In connection with our 2007 oil and gas property acquisition, 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 and put prices for the natural gas volumes and a $5.00 per barrel change in the average swap price for the oil volumes covered by the outstanding hedging contracts is as follows (in millions):

	+/- $1.00/MMbtu	+/- $5.00/Bbl
Swaps	$ 2.6	$ 0.6
Puts	1.2	0.3

Because 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

For information regarding our adoption of accounting standards, see Note 1 in Item 8. of this Form 10-K. We do not expect the adoption of any accounting standards in 2010 to have a material impact to 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 2008 and 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, 2009, 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's 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, 2009, 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, 2009 and 2008, and the related consolidated statements of operations, cash flow, and changes in stockholders' equity for each of the three years in the period ended December 31, 2009, and our report dated March 12, 2010 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana
March 12, 2010

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. as of December 31, 2009 and 2008, and the related consolidated statements of operations, cash flows, and changes in stockholders' equity for each of the three years in the period ended December 31, 2009. 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, 2009 and 2008, and the consolidated results of its operations and its cash flow for each of the three years in the period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, McMoRan changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements.

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, 2009, based on criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 12, 2010, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana
March 12, 2010

McMoRan EXPLORATION CO.
CONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2008
	(In Thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 241,418	$ 93,486
Accounts receivable	79,681	112,684
Inventories	47,818	31,284
Prepaid expenses	14,457	13,819
Fair value of oil and gas derivative contracts	8,693	31,624
Current assets from discontinued operations, including restricted cash of $470	825	516
Total current assets	392,892	283,413
Property, plant and equipment, net	796,223	992,563
Restricted cash	41,677	29,789
Deferred financing costs and other assets	11,931	15,658
Fair value of oil and gas derivative contracts	-	5,847
Long-term assets from discontinued operations	6,159	3,012
Total assets	$ 1,248,882	$ 1,330,282
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 66,544	$ 77,009
Accrued liabilities	51,945	89,565
Accrued interest and dividends payable	8,535	7,586
Current portion of accrued oil and gas reclamation costs	106,791	103,550
Fair value of oil and gas derivative contracts	1,237	-
Current portion of accrued sulphur reclamation costs (discontinued operations)	8,300	785
Other current liabilities from discontinued operations	1,183	1,317
Total current liabilities	244,535	279,812
5¼% convertible senior notes	74,720	74,720
11.875% senior notes	300,000	300,000
Accrued oil and gas reclamation costs	321,920	317,651
Other long-term liabilities	16,602	20,023
Accrued sulphur reclamation costs (discontinued operations)	19,152	22,218
Other long-term liabilities from discontinued operations	6,145	6,835
Total liabilities	$ 983,074	$ 1,021,259
Commitments and contingencies (Note 16)		

McMoRan EXPLORATION CO.
CONSOLIDATED BALANCE SHEETS
(Continued)

	December 31, 2009	December 31, 2008
	(In Thousands)	
Stockholders' equity:		
Preferred stock, par value $0.01, 50,000,000 shares authorized, 1,675,590 and 1,589,340 shares issued and outstanding (liquidation preference), respectively (Note 8)	$ 245,184	$ 158,934
Common stock, par value $0.01, 150,000,000 shares authorized, 88,555,685 shares and 72,981,734 shares issued and outstanding, respectively	885	730
Capital in excess of par value of common stock	1,053,684	971,977
Accumulated deficit	(987,139)	(776,153)
Accumulated other comprehensive loss	(346)	(22)
Common stock held in treasury, 2,511,132 shares and 2,508,660 shares, at cost, respectively	(46,460)	(46,443)
Total stockholders' equity	265,808	309,023
Total liabilities and stockholders' equity	$ 1,248,882	$ 1,330,282

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

McMoRan EXPLORATION CO.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2009	2008	2007
	(In Thousands, Except Per Share Amounts)		
Revenues:			
Oil and natural gas	$ 422,976	$ 1,058,804	$ 475,250
Service	12,459	13,678	5,917
Total revenues	435,435	1,072,482	481,167
Costs and expenses:			
Production and delivery costs	193,025	258,450	122,127
Depletion, depreciation and amortization expense	313,980	854,798	256,007
Exploration expenses	94,281	79,116	58,954
(Gain) loss on oil and gas derivative contracts	(17,394)	(16,303)	5,181
General and administrative expenses	42,954	48,999	27,973
Main Pass Energy Hub™ costs	1,615	6,047	9,754
Insurance recoveries (Note 4)	(24,592)	(3,391)	(2,338)
Total costs and expenses	603,869	1,227,716	477,658
Operating income (loss)	(168,434)	(155,234)	3,509
Interest expense, net	(42,943)	(50,890)	(66,366)
Other income (expense), net	4,043	(2,566)	(704)
Loss from continuing operations before income taxes	(207,334)	(208,690)	(63,561)
Income tax benefit (expense)	2,445	(2,508)	-
Loss from continuing operations	(204,889)	(211,198)	(63,561)
Income (loss) from discontinued operations	(6,097)	(5,496)	3,827
Net loss	(210,986)	(216,694)	(59,734)
Preferred dividends, amortization of convertible preferred stock issuance costs and inducement payments for early conversion of preferred stock	(14,332)	(22,286)	(4,172)
Net loss applicable to common stock	$ (225,318)	$ (238,980)	$ (63,906)
Basic and diluted net loss per share of common stock:			
Net loss from continuing operations	$(2.79)	$(3.79)	$(1.97)
Net income (loss) from discontinued operations	(0.08)	(0.09)	0.11
Net loss per share of common stock	$(2.87)	$(3.88)	$(1.86)
Average common shares outstanding:			
Basic and diluted	78,625	61,581	34,283

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

McMoRan EXPLORATION CO.
CONSOLIDATED STATEMENTS OF CASH FLOW

	Years Ended December 31,		
	2009	2008	2007
		(In Thousands)	
Cash flow from operating activities:			
Net loss	$ (210,986)	$ (216,694)	$ (59,734)
Adjustments to reconcile net loss to net cash provided by operating activities:			
(Income) loss from discontinued operations	6,097	5,496	(3,827)
Depletion, depreciation and amortization expense	313,980	854,798	256,007
Exploration drilling and related expenditures, net	61,504	37,841	22,832
Compensation expense associated with stock-based awards	14,193	30,223	13,107
Amortization of deferred financing costs	3,725	4,630	14,713
Change in fair value of oil and gas derivative contracts	28,631	(40,612)	5,181
Loss on induced conversion of convertible senior notes	-	2,663	-
Reclamation expenditures, net of prepayments by third parties	(45,885)	(29,432)	(10,622)
Increase in restricted cash	(15,049)	(15,152)	(3,748)
Payment to fund terminated pension plan	-	(2,291)	-
Purchase of oil and gas derivative contracts and other	(720)	(155)	(4,335)
(Increase) decrease in working capital:			
Accounts receivable-customers	(4,868)	40,900	(51,433)
Accounts receivable-joint interest partners	34,545	(25,270)	(10,099)
Accounts receivable-other	799	1,461	(2,228)
Accounts payable and accrued liabilities	(33,281)	8,618	17,781
Inventories	(16,535)	(19,777)	13,527
Prepaid expenses	743	(7,588)	12,526
Net cash provided by continuing operations	136,893	629,659	209,648
Net cash used in discontinued operations	(5,728)	(6,262)	(2,010)
Net cash provided by operating activities	131,165	623,397	207,638
Cash flow from investing activities:			
Exploration, development and other capital expenditures	(138,015)	(236,383)	(153,210)
Acquisition of properties, net	-	(2,826)	(1,047,936)
Proceeds from restricted investments	-	-	6,056
Increase in restricted investments	-	-	(126)
Net cash used in continuing activities	(138,015)	(239,209)	(1,195,216)
Net cash from discontinued operations	-	-	-
Net cash used in investing activities	$ (138,015)	$ (239,209)	$ (1,195,216)

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

	Years Ended December 31,		
	2009	2008	2007
		(In Thousands)	
Cash flow from financing activities:			
Net proceeds from sale of common stock	$ 84,976	$ -	$ 200,189
Net proceeds from sale of preferred stock	83,275	-	250,385
(Payments) borrowings under senior secured revolving credit facility, net	-	(274,000)	245,250
Proceeds from sale of 11.875% senior notes	-	-	300,000
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)
Dividends paid and inducement payments on early conversion of convertible preferred stock	(13,469)	(23,565)	(1,121)
Payments for induced conversion of convertible senior notes	-	(2,663)	-
Proceeds from exercise of stock options, warrants and other	-	4,696	10,428
Net cash provided by (used in) continuing operations	154,782	(295,532)	974,578
Net cash activity from discontinued operations	-	-	-
Net cash provided by (used in) financing activities	154,782	(295,532)	974,578
Net increase (decrease) in cash and cash equivalents	147,932	88,656	(13,000)
Cash and cash equivalents at beginning of year	93,486	4,830	17,830
Cash and cash equivalents at end of year	$ 241,418	$ 93,486	$ 4,830
Interest paid	$ 43,059	$ 55,181	$ 67,622
Income taxes paid	$ 2,332	$ 3,370	$ -

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

	Years Ended December 31,		
	2009	2008	2007
	(In Thousands, Except Share & Per Share Amounts)		
8% Convertible Perpetual Preferred Stock:			
Balance at beginning of year	$ -	$ -	$ -
Shares sold in equity offering, representing 86,250 shares	86,250	-	-
Balance at end of year, representing 86,250 shares in 2009 and no shares in 2008 and 2007	86,250	-	-
6 ¾% Mandatorily Convertible Preferred Stock:			
Balance at beginning of year, representing 1,589,340 shares in 2009, 2,587,500 in 2008 and no shares in 2007	158,934	258,750	-
Shares converted in privately negotiated transaction, representing 998,160 shares	-	(99,816)	-
Shares sold in equity offering, representing 2,587,500 shares	-	-	258,750
Balance at end of year, representing 1,589,340 shares in 2009 and 2008 and 2,587,500 shares in 2007	158,934	158,934	258,750
Common Stock:			
Balance at beginning of year representing 72,981,734 shares in 2009, 55,795,251 shares in 2008 and 30,740,275 shares in 2007	730	558	307
Shares issued in equity offering representing 15,547,400 shares (at $5.75 per share) in 2009 and 16,887,500 shares (at $12.40 per share) in 2007 (Note 8)	155	-	169
Shares issued in debt conversion transactions representing 9,508,743 shares in 2008	-	95	-
Exercise of stock warrants representing 636,811 shares in 2008 and 1,742,424 shares in 2007	-	7	17
Exercise of stock options and other representing 26,551 in 2009, 332,896 shares in 2008 and 219,633 shares in 2007	-	3	3
Preferred stock conversions representing 6,708,033 shares in 2008 and 6,205,419 shares in 2007	-	67	62
Balance at end of year representing, 88,555,685 shares in 2009, 72,981,734 shares in 2008 and 55,795,251 shares in 2007	885	730	558
Capital in Excess of Par Value:			
Balance at beginning of year	971,977	718,472	477,178
Costs associated with preferred stock equity offering	(2,975)	-	(8,365)
Common stock equity offering, net of offering costs	84,821	-	200,020
Shares issued in debt conversion transactions	-	140,127	-
Preferred stock conversions	-	99,749	29,786
Stock-based compensation expense	14,193	30,223	13,107
Exercise of stock options and warrants	-	5,692	10,917
Dividends and inducement payments on preferred stock and amortization of related issuance cost	(14,332)	(22,286)	(4,171)
Balance at end of year	1,053,684	971,977	718,472

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

	Years Ended December 31,		
	2009	2008	2007
	(In Thousands, Except Share Amounts)		
Accumulated Deficit:			
Balance at beginning of year	$ (776,153)	$ (559,459)	$ (499,725)
Net loss	(210,986)	(216,694)	(59,734)
Balance at end of year	(987,139)	(776,153)	(559,459)
Accumulated Other Comprehensive Loss:			
Balance at beginning of year	(22)	(653)	(1,273)
Amortization of previously unrecognized pension components, net	(40)	(40)	31
Change in unrecognized net gains/losses of pension plans	(284)	671	589
Balance at end of year	(346)	(22)	(653)
Common Stock Held in Treasury:			
Balance at beginning of year representing, 2,508,660 shares in 2009, 2,471,674 shares in 2008 and 2,433,545 in 2007	(46,443)	(45,439)	(44,930)
Tender of 2,472 shares in 2009, 36,986 shares in 2008 and 38,129 shares in 2007 associated with the exercise of stock options and the vesting of restricted stock	(17)	(1,004)	(509)
Balance at end of year representing 2,511,132 shares in 2009, 2,508,660 shares in 2008 and 2,471,674 shares in 2007	(46,460)	(46,443)	(45,439)
Total stockholders' equity	$ 265,808	$ 309,023	$ 372,229

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. McMoRan's consolidated financial statements include the accounts of those subsidiaries where McMoRan directly or indirectly has more than 50 percent of the voting rights and where the right to participate in significant management decisions is not shared with other shareholders, including its two wholly owned subsidiaries, McMoRan Oil & Gas LLC (MOXY) and Freeport-McMoRan Energy LLC (Freeport Energy). MOXY conducts all of McMoRan's oil and gas operations and the long-term business objective of Freeport Energy may include the pursuit of a multifaceted energy services facility, including the potential development of liquefied natural gas (LNG) regasification and storage facility 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. Changes in the accounting principles applied during 2009, none of which impacted the consistency of presentation, are discussed below under the caption "New Accounting Standards."

McMoRan's former sulphur operations are presented as discontinued operations, and the major classes of assets and liabilities related to its sulphur business are separately shown for the periods presented.

On August 6, 2007, MOXY completed an acquisition of oil and gas properties (Note 9). McMoRan's consolidated financial statements include the results of operations of the acquired properties for the years ended December 31, 2009 and 2008 and the period from August 6, 2007 (closing date) to 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's long-term business objectives may include the pursuit of a multifaceted energy services facility, including potential LNG facilities and storage capabilities at Main Pass Block 299 (Main Pass) in the Gulf of Mexico.

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 and the carrying value of long-lived assets and assets held for sale or disposal. 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 16).

Accounts Receivable. The majority of McMoRan's accounts receivable result from oil and natural gas sales or joint interest billings to third parties in the energy industry. McMoRan has not historically had any significant collection problems, and no allowance for doubtful accounts is included in the accompanying financial statements.

Inventories. Product inventories totaled $0.6 million at December 31, 2009 and $1.0 million at December 31, 2008, consisting entirely of oil at Main Pass. Materials and supplies inventory totaled $47.2 million at December 31, 2009 and $30.3 million at December 31, 2008 and represents the cost of supplies to be used in McMoRan's drilling activities, primarily drilling pipe and tubulars. A portion of the cost of such inventory will be reimbursed to McMoRan by joint operating partners as future well drilling activity utilizes these materials. McMoRan's inventories are stated at the lower of weighted average cost or market. As a result of declines in market values of certain inventory items, McMoRan recorded a write-down of $3.3 million during 2009 for materials not dedicated to currently planned drilling projects. There were no required reductions in the carrying value of McMoRan's inventories during 2008.

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.
  * Drilling costs that no longer meet the criteria for continued capitalization under U.S. generally accepted accounting principles, but for which management intends to pursue development activities, are charged to depletion, depreciation and amortization expense.
  * 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 semi-annually. 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 \$3.9 million in 2009, \$5.0 million in 2008 and \$6.3 million in 2007.

Sulphur. Note 11 includes results associated with McMoRan's 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.

Asset Impairment. Costs of unproved oil and gas properties are assessed periodically and a loss is recognized if the properties are deemed impaired. When events or circumstances indicate that proved oil and gas property carrying amounts might not be recoverable from estimated future undiscounted cash flows from the property, a reduction of the carrying amount to fair value is required. Measurement of the impairment loss is based on the estimated fair value of the asset, which McMoRan generally determines using estimated undiscounted future cash flows from the property, adjusted to present value using an interest rate considered appropriate for the asset. Future cash flow estimates for McMoRan's oil and gas properties are measured on a field-by-field basis and include future estimates of proved and risk-adjusted probable reserves, oil and gas prices, production rates and operating and development costs based on operating budget forecasts.

The determination of oil and natural gas reserve estimates is a subjective process, and the accuracy of any reserve estimate depends on the quality of available data and the application of engineering and geological interpretation and judgment. Estimates of economically recoverable reserves and future net cash flows depend on a number of variable factors and assumptions that are difficult to predict and may vary considerably from actual results. In particular, reserve estimates for wells with limited or no production history are less reliable than those based on actual production. Subsequent evaluation of the same reserves may result in variations, which may be substantial, in estimated reserves and related future cash flow estimates. If the capitalized cost of an individual oil and gas property exceeds the related estimated future net cash flows, an impairment charge to reduce the capitalized costs to the property's estimated fair value is required (Note 4).

Revenue Recognition and Gas Balancing. 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 reasonably 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, 2009, McMoRan had natural gas imbalance receivables of $5.4 million and a liability of $8.0 million for over deliveries. At December 31, 2008, McMoRan had natural gas imbalance receivables of $9.2 million and a liability of $12.6 million for over deliveries.

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 certain amounts of production, with each field's eligible amount of relief determined by specific MMS criteria and subject to their final approval. Fluctuations in the amount of royalty relief revenue recognized will primarily occur based the number of properties that qualify for relief in a given year. During the three year period ended December 31, 2009, McMoRan recognized $4.0 million in 2009, $17.7 million in 2008 and $3.7 million in 2007 of 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 the annual NYMEX market price for natural gas exceeds the MMS's annual price threshold, then relief is suspended under the program for that year and royalties would be due to the MMS with interest. 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 or estimated to be exceeded based on forward pricing at the end of a reporting period, McMoRan defers all such revenues until the threshold price is no longer exceeded. The price threshold was not exceeded for the years ending December 31, 2009, 2008 or 2007.

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, 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 fees for processing third-party oil production through the oil facilities at Main Pass, other third party management fees and standardized industry (COPAS) overhead charges McMoRan receives as operator of oil and gas properties.

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 and in-house engineers 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 16).

Comprehensive Loss. McMoRan follows U.S. generally accepted accounting principles for the reporting and display of comprehensive loss (net loss adjusted for other comprehensive income (loss), or all other changes in net assets from nonowner sources) and its components (Note 14).

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 will account for any such financial contracts and other derivatives in accordance with U.S generally accepted accounting principles. 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 related counterparty credit risk on an ongoing basis and considers this risk to be minimal.

In connection with the 2007 oil and gas property acquisition, 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 these 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 in 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 (Note 7).

Earnings Per Share. Basic net loss per share of common stock is 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 (Note 10).

Stock-Based Compensation. Compensation cost recognized includes compensation cost for all stock option awards granted based on the grant-date fair value and restricted stock units granted which are estimated in accordance with U.S. generally accepted accounting principles. 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 based on length of service. McMoRan includes estimated forfeitures in its compensation cost and updates the estimated forfeiture rate through the final vesting date of the awards (Note 12).

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 13).

New Accounting Standards. In December 2007, the Financial Accounting Standards Board (FASB) issued an accounting standard that 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 purchase price. Transaction costs are expensed as incurred and not considered as part of the fair value of the acquisition; however, acquired research and development are no longer expensed at acquisition, but instead are capitalized as an indefinite-lived intangible asset. McMoRan adopted this accounting standard on January 1, 2009 with no impact to its financial statements.

In April 2009, the FASB issued accounting guidance that requires assets acquired and liabilities assumed in a business combination that arise from contingencies be recognized at fair value, if the fair value can be determined during the measurement period. McMoRan adopted this accounting guidance effective June 30, 2009 with no impact to its financial statements.

In March 2008, the FASB issued an accounting standard that requires enhanced disclosure related to derivatives and hedging activities and thereby seeks to improve the transparency of financial reporting. Entities are required to provide enhanced disclosures relating to: (a) how and why an entity uses derivative instruments; (b) how derivative instruments and related hedge items are accounted for under GAAP; and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. This standard was applied prospectively to all derivative instruments and non-derivative instruments that are designated and qualify as hedging instruments and related hedged items for all financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. McMoRan adopted this accounting standard on January 1, 2009 and has added certain additional disclosures in its financial statements.

In May 2008, the FASB issued accounting guidance that requires the issuer of certain convertible debt instruments that may be settled in cash (or other assets) on conversion to separately account for the liability (debt) and equity (conversion option) components of the instrument in a manner that reflects the issuer's nonconvertible debt borrowing rate. This requires the accretion of the resulting discount on the liability component of the convertible debt, which results in additional interest expense based on McMoRan's nonconvertible debt borrowing rate. McMoRan adopted this guidance on January 1, 2009 with no impact to its financial statements due to McMoRan's instruments' inability to be settled in cash except for specific circumstances which are not within the scope of this guidance.

In June 2008, the FASB issued accounting guidance to clarify that unvested share-based payment awards with a right to receive non-forfeitable dividends are participating securities. McMoRan adopted this guidance on January 1, 2009 with no impact to its financial statements as its instruments do not meet the definition of participating securities as defined in the guidance.

In December 2008 the Securities and Exchange Commission (SEC) approved amendments to revise its oil and gas reserve estimation and disclosure requirements. The amendments among other things:

- allow the use of new technologies to determine proved reserves;
- permit the optional disclosure of probable and possible reserves;
- modify the prices used to estimate reserves for SEC disclosure purposes to a 12-month average price instead of a period-end price; and
- require that if a third party is primarily responsible for preparing or auditing the reserve estimates, the company make disclosures relating to the independence and qualifications of the third party, including filing as an exhibit any report received from the third party.

The new SEC reserve estimation and disclosure requirements are effective for McMoRan's disclosures included in this Form 10-K.

In January 2010, the FASB issued accounting guidance to align the reserve calculation and disclosure requirements of U.S. generally accepted accounting principles with the new SEC oil and gas reserve estimation and disclosure rules. McMoRan adopted this accounting guidance effective for its December 31, 2009 financial statements (Note 18).

In April 2009, the FASB issued accounting guidance that extends the fair value disclosure requirements to interim financial statements of publicly traded companies. Disclosures of the fair value of all financial instruments (recognized or unrecognized), except for specific listed instruments, is required when practicable to do so. These fair value disclosures must be presented together with the related carrying amount of the financial instruments in a manner that clearly distinguishes between assets and liabilities and indicates how the carrying amounts relate to amounts reported on the balance sheet. An entity must also disclose the method(s) and significant assumptions used to estimate the fair value of financial instruments. McMoRan adopted this accounting guidance on June 30, 2009 with limited impact to its financial statement disclosures.

In May 2009, the FASB issued an accounting standard that establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Specifically, this standard provides:

- The period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements;
- The circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and
- The disclosures that an entity should make about events or transactions that occurred after the balance sheet date.

McMoRan adopted this accounting standard on June 30, 2009 with limited impact to its financial statement disclosures. McMoRan has evaluated subsequent events for purposes of its year end 2009 financial reporting through the date of filing of this annual report on Form 10-K with the SEC.

In June 2009, the FASB issued accounting guidance that establishes the FASB Accounting Standards Codification as the sole source of authoritative generally accepted accounting principles.

McMoRan adopted this accounting guidance on September 30, 2009 and updated references to generally accepted accounting principles in its financial statements. The adoption of this accounting guidance did not impact McMoRan's financial position or results of operations.

2. OIL & GAS EXPLORATION ACTIVITIES

McMoRan's oil and gas operations are conducted through MOXY, whose operations and properties are located 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, 2009, McMoRan owned or controlled interests in 352 oil and gas leases in the Gulf of Mexico and onshore Louisiana and Texas covering 0.97 million gross acres (0.48 million acres net to McMoRan's interests). McMoRan's acreage position includes 0.77 million gross acres (0.42 million acres net to McMoRan's interest) located on the outer continental shelf of the Gulf of Mexico. This acreage position includes 0.04 million gross acres (0.01 million acres net to McMoRan's interest) associated with McMoRan's ultra-deep gas play which are held by Suspension of Operations approval from the MMS and which are expected to be maintained by drilling or renewal during 2010. Less than 0.1 million of McMoRan's net leasehold interests are scheduled to expire in 2010. 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, 2009. 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)	547,773	315,814	223,678	106,653
Onshore Louisiana and Texas	35,943	18,250	61,775	24,398
Total at December 31, 2009	583,716	334,064	285,453	131,051

Exploration Funding Arrangements

McMoRan intends to continue to pursue growth in reserves and production through the exploration, exploitation and development of both existing and new potential prospects. McMoRan will continue to be responsive to economic conditions by managing its capital program while also continuing to seek to build asset values through its focused drilling program. 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.

In 2009, McMoRan entered into an agreement with W.A. "Tex" Moncrief Jr. (Moncrief) to participate in its ultra-deep drilling program. Moncrief agreed to fund drilling and production operations on a promoted basis to explore and develop targets below 25,000 feet (ultra-deep prospects). McMoRan and two of its partners assigned 10 percent of the group's collective working interest in Davy Jones to Moncrief. Moncrief may also participate for 10 percent of the collective interests of these parties in future ultra-deep wells.

Also in 2009, McMoRan entered into an arrangement with a private partner allowing that partner to participate in certain of its ongoing exploration and development activities. The private partner's initial funding commitment was $30 million. Additional commitments, if any, for the partner's participation and funding of future joint projects beyond the initial $30 million committed investment are at the discretion of the private partner.

3. ACCOUNTS RECEIVABLE AND MAJOR CUSTOMERS

The components of accounts receivable follow (in thousands):

	December 31, 2009	December 31, 2008
Accounts receivable:		
Customers	$ 55,144	$ 50,275
Joint interest partners	22,966	60,039
Other	1,571	2,370
Total accounts receivable	$ 79,681	$ 112,684

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, 2009 is as follows:

Individual Customer	Year Ended December 31, 2009	2008	2007
A	32%	35%	27%
B	15	<10	<10
C	10	18	24
D	<10	12	13

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.

4. PROPERTY, PLANT AND EQUIPMENT

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

	December 31, 2009	December 31, 2008
Oil and gas property, plant and equipment	$ 2,246,397	$ 2,163,577
Other	31	31
	2,246,428	2,163,608
Accumulated depletion, depreciation and amortization	(1,450,205)	(1,171,045)
Property, plant and equipment, net	$ 796,223	$ 992,563

Impairment

The components of McMoRan's depletion, depreciation and amortization expense are summarized below (in thousands):

	Years Ended December 31, 2009	2008	2007
Depletion and depreciation expense	$ 205,479	$ 357,458	$ 228,540
Accretion expense	33,186	164,753	13,872
Impairment charges/losses	75,315	332,587	13,595
Total depletion, depreciation and amortization expense	$ 313,980	$ 854,798	$ 256,007

As discussed in Note 1, when events and circumstances indicate that proved oil and gas property carrying amounts might not be recoverable from estimated future undiscounted cash flows, a reduction of the carrying amount to estimated fair value is required. McMoRan estimates the fair value of its properties using estimated future cash flows based on proved and risk-adjusted probable oil and natural gas reserves as estimated by independent reserve engineers. Future cash flows are determined using published forward market prices adjusted for property-specific price basis differentials, net of estimated future production and development costs and excluding estimated asset retirement and abandonment expenditures. If the undiscounted cash flows indicate that the property is impaired, McMoRan discounts the future cash flows using a discount factor that considers third-party investors' expected rates of return for similar type assets if acquired under current market conditions.

Due to the declines in market prices for oil and natural gas and the impact of operational factors that negatively impacted reserve recoverability, McMoRan recorded impairment charges totaling $75.3 million during 2009.

Due to the significant decline in market prices for oil and natural gas that occurred in the fourth quarter of 2008, McMoRan recorded impairment charges of $246.9 million. McMoRan also recorded impairment charges totaling $44.9 million on two oil and gas properties (Mound Point South and JB Mountain Deep) after re-considering its then near term drilling plans under market conditions at that time. Additionally, McMoRan recorded other charges in 2008 totaling $40.8 million to write off its remaining investments in various wells following unsuccessful attempts to establish production at certain wells and after significant damage was incurred at two wells during Hurricane Ike. In addition, asset retirement related accretion expense totaling $124.4 million was recorded during 2008 associated with certain properties impacted by Hurricane Ike.

In 2007, McMoRan recorded an impairment charge related to one field totaling $13.6 million.

As discussed above, during 2009 and 2008 the continued decline in market prices for oil and natural gas coupled with other operational factors triggered impairment assessments that ultimately resulted in significant impairment charges for several of McMoRan's oil and gas property investments. Additional impairment charges may be recorded in future periods if market conditions experienced in the latter half of 2008 and extending through 2009 continue to weaken, or if other unforeseen operational issues occur that negatively impact McMoRan's ability to fully recover its current investments in oil and gas properties.

Insurance

Hurricanes Gustav and Ike disrupted McMoRan's Gulf of Mexico operations prior to making landfall on the Louisiana and Texas coasts on September 1, 2008 and September 13, 2008, respectively. There was no significant damage to McMoRan's properties resulting from Hurricane Gustav. However, Hurricane Ike caused significant structural damage to several platforms in which McMoRan had an investment interest. Since the third quarter of 2008, McMoRan has recorded charges totaling in excess of $180 million related to incurred repair costs, property impairments and additional estimated reclamation costs associated with the damaged properties. While a portion of these costs has been funded to date, a significant amount of the remaining expenditures, particularly for asset retirement obligations, will be funded by McMoRan over the next several years. McMoRan expects to realize a substantial recovery in future periods under its insurance program for a large portion of these hurricane related costs, reimbursement for which will be received after damage-related expenditures are funded and related claims are approved. McMoRan received net insurance proceeds of $24.6 million in 2009, after satisfying its $50 million deductible, as partial payments associated with certain of McMoRan's insured hurricane-related losses.

McMoRan did not record any insurance recoveries in 2008 related to Hurricane Ike; however, it did receive final settlement on its Hurricane Katrina property loss claim of $3.4 million. In 2007, McMoRan received insurance recoveries totaling $2.3 million related to its Hurricane Katrina claim.

5. OTHER ASSETS AND OTHER LIABILITIES

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, 2009			December 31, 2008		
	Gross Carrying Amount	Accumulated Amortization	Net	Gross Carrying Amount	Accumulated Amortization	Net
11.875% Senior Notes (due November 2014)	$ 8,055	$ (2,451)	$ 5,604	$ 8,055	$ (1,301)	$ 6,754
Revolving Credit Facility (matures August 2012)	11,377	(5,820)	5,557	11,377	(3,679)	7,698
5¼% Convertible Senior Notes (due October 2011)	6,243	(5,473)	770	6,243	(5,037)	1,206
	$ 25,675	$ (13,744)	$ 11,931	$ 25,675	$ (10,017)	$ 15,658

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

	December 31,	
	2009	2008
Advances from third parties for future abandonment costs (Note 16)	$ 7,767	$ 7,728
Employee postretirement medical liability (Note 12)	4,346	4,387
Liability for management services (Note 15)	2,734	2,739
Nonqualified pension plan liability	1,395	1,370
Accrued workers compensation and group insurance	360	638
Sulphur-related environmental liability (Note 16)	-	3,161
	$ 16,602	$ 20,023

6. LONG-TERM DEBT

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

	December 31,	
	2009	2008
11.875% senior notes (due 2014)	300,000	300,000
5¼% convertible senior notes (due 2011)	74,720	74,720
Total debt	374,720	374,720
Less current maturities	-	-
Long-term debt	$ 374,720	$ 374,720

Variable Rate Senior Secured Revolving Credit Facility

McMoRan's variable rate senior secured revolving credit facility (credit facility) matures in August 2012. The borrowing capacity was $175 million at December 31, 2009. McMoRan had no borrowings outstanding under the credit facility as of December 31, 2009, and did not borrow under the credit facility during 2009. A letter of credit in the amount of $100 million remains outstanding under the credit facility to support a portion of the reclamation obligations assumed in the 2007 oil and gas property acquisition (Note 9).

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

Interest on the facility currently accrues at LIBOR plus 2.75 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 in the same manner. The average interest rate on borrowings under the facility was 5.5 percent in 2008 and 7.5 percent in 2007. Interest expense on the credit facility totaled $5.7 million, representing amortization expense associated with the credit facility's related deferred financing costs and other fees for the year ended

December 31, 2009; $11.9 million, including $6.3 million of commitment fees and amortization of related deferred financing costs for the year ended December 31, 2008; and $13.3 million including $2.2 million of commitment fees and amortization of related deferred financing costs for the year ended December 31, 2007.

The credit facility contains covenants and other restrictions customary for oil and gas borrowing base credit facilities, including limitations on debt, liens, dividends, voluntary redemptions of debt, investments, asset sales and transactions with affiliates. In addition, the credit facility requires that McMoRan maintain certain financial tests, including a leverage test (Total Debt to EBITDAX, as those terms are defined in the facility, for the preceding four quarters) and a secured leverage test (First Lien Debt to EBITDAX, as those terms are defined in the facility, for the preceding four quarters), and a current ratio test (current assets to current liabilities, subject to certain adjustments as of the end of the quarter).

McMoRan was in compliance with these covenants at December 31, 2009. At December 31, 2009, the carrying value of the credit facility approximated fair value because the interest rate is variable and is reflective of market rates.

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 19). 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 restrict 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 2009 and 2008 totaled $36.8 million, including amortization of related deferred financing costs of $1.2 million. The fair value of the 11.875% senior notes, which is determined at the end of each reporting period using inputs based upon quoted prices for such instruments in active markets, was approximately $307.1 million at December 31, 2009 and $207.0 million at December 31, 2008.

Convertible Senior Notes

On October 6, 2004, McMoRan completed a private placement of $140 million of 5¼% convertible senior notes due October 6, 2011 (5¼% notes). Net proceeds from the 5¼% 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 5¼% 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 $4.4 million, $5.0 million and $6.7 million for the years ended December 31, 2009, 2008 and 2007, respectively, including amortization of deferred financing costs of $0.4 million in 2009, $0.5 million in 2008 and $0.7 million in 2007. The 5¼% 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. Since October 6, 2009, McMoRan had 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 the notes prior to the redemption date, provided the closing price of McMoRan's common stock exceeded 130 percent of the conversion price for at least 20 trading days in any consecutive 30-day trading period.

During 2008, McMoRan privately negotiated transactions to induce the conversion of $40.2 million of the 5¼% notes into approximately 2.4 million shares of McMoRan's common stock. McMoRan paid an aggregate $1.7 million in cash to induce these conversions, which is reflected as non-operating expense in the consolidated statements of operations.

On July 3, 2003, McMoRan issued $130 million of 6% convertible senior notes due July 2, 2008 (6% notes). Net proceeds from the 6% 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 6% notes were otherwise unsecured. Interest payments were payable on January 2 and July 2 of each year, and began on January 2, 2004 and ended in 2008. Interest expense totaled $1.7 million in 2008 and $7.2 million in 2007. Amortization of the related deferred financing costs totaled $0.4 million in 2008 and $1.1 million in 2007. During 2008, McMoRan privately negotiated transactions to induce the conversion of $39.1 million of the 6% notes into approximately 2.75 million shares of McMoRan's common stock. McMoRan paid an aggregate of $1.0 million in cash to induce these conversions, which is reflected as non-operating expense in the consolidated statements of operations. Additionally, $61.7 million of the 6% notes were converted into approximately 4.3 million shares of McMoRan common stock in accordance with the terms of the 6% notes (including $43.5 million of the 6% notes converted into shares of common stock upon maturity on July 2, 2008).

The fair value of the 5¼% notes, which is determined at the end of each reporting period using inputs based upon quoted prices for such instruments in active markets, was $70.3 million at December 31, 2009 and $62.9 million at December 31, 2008.

Unsecured Bridge Loan Facility
On August 6, 2007, McMoRan entered into an $800 million interim bridge loan facility (bridge loan) in conjunction with the 2007 oil and gas property acquisition and initially borrowed $800 million to partially fund the acquisition costs. 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 senior notes 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 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 at that time under our previous revolving credit facility.

At the closing of the 2007 oil and gas property acquisition, 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 financing 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.

7. DERIVATIVE CONTRACTS
In connection with the closing of the 2007 oil and gas property acquisition (Note 9) 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 for the years 2008 through 2010. At December 31, 2009, McMoRan's remaining outstanding oil and gas derivative contracts were 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
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
2010	118	$ 70.89	50	$ 50.00	168

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

Because these oil and gas derivative contracts were not designated as hedges for accounting purposes, unrealized (gains) losses representing changes in the related fair values along with realized (gains) losses representing cash settlements are recognized immediately in McMoRan's operating results at each reporting period. McMoRan's realized and unrealized (gains) losses on these contracts were as follows (in thousands):

	Years Ended December 31,		
	2009	2008	2007
Realized (gain) loss			
Gas puts	$ (6,700)	$ 2,209	$ -
Oil puts	238	356	-
Gas swaps	(33,818)	4,005	-
Oil swaps	(5,745)	17,739	-
Total realized (gain) loss	(46,025)	24,309	-
Unrealized (gain) loss			
Gas puts	1,167	(3,178)	1,433
Oil puts	929	(1,483)	630
Gas swaps	18,002	(7,872)	(17,665)
Oil swaps	8,533	(28,079)	20,783
Total unrealized (gain) loss	28,631	(40,612)	5,181
(Gain) loss on oil and gas derivative contracts	$ (17,394)	$ (16,303)	$ 5,181

The original cost of the put options was $4.6 million. There was no cost for entering into the swap contracts. The derivative contracts are reported at fair value on McMoRan's balance sheets. The fair value of McMoRan's swaps and puts is based on transaction counterparty acknowledgments and corroborated based on quoted market prices and internal valuation model analyses. McMoRan has classified the fair value measurement of its derivative instruments as being derived from Level 2 inputs, as defined under U.S. generally accepted accounting principles. The following table provides fair value measurement information as of December 31, 2009 and 2008 (in thousands):

	December 31, 2009				
	Puts		Swaps		
	Gas	Oil	Gas	Oil	Total
Current assets	$ 1,113	$ 45	$ 7,535	$ -	$ 8,693
Current liabilities	-	-	-	(1,237)	(1,237)
Fair value of contracts	$ 1,113	$ 45	$ 7,535	$ (1,237)	$ 7,456

	December 31, 2008				
	Puts		Swaps		
	Gas	Oil	Gas	Oil	Total
Current assets	$ 2,659	$ 915	$ 21,701	$ 6,349	$ 31,624
Other assets	765	297	3,837	948	5,847
Fair value of contracts	$ 3,424	$ 1,212	$ 25,538	$ 7,297	$ 37,471

8. COMMON STOCK AND MANDATORILY REDEEMABLE PREFERRED STOCK OFFERINGS

In June 2009, McMoRan completed concurrent public offerings of 15.5 million shares of common stock at $5.75 per share and 86,250 shares of 8% convertible perpetual preferred stock (8% preferred stock) with an offering price of $1,000 per share. The net proceeds from these offerings, after deducting underwriters' discounts and other expenses, were approximately $168.3 million. McMoRan is using the net proceeds from the offerings for general corporate purposes, including funding its capital expenditures.

The 8% preferred stock is recorded at liquidation preference value ($1,000 per share) in the accompanying consolidated balance sheet. The first quarterly cash dividend was $11.78 per share (reflecting the partial quarter) and was paid on August 15, 2009, and subsequent quarterly dividend payments are $20.00 per share. The 8% preferred stock is convertible in the aggregate into 12.6 million shares of McMoRan common stock (equivalent to a conversion price of $6.8425 per share), subject to certain anti-dilution adjustments. Beginning June 15, 2014, McMoRan has the right to redeem shares of the 8% preferred stock by paying cash, McMoRan common stock or any combination thereof for $1,000 per share plus accumulated and unpaid dividends, but only if the trading price of McMoRan's common stock has exceeded 130% of the initial conversion price for at least 20 trading days within a period of 30 consecutive trading days ending on the trading day before the date McMoRan gives the redemption notice.

In February 2010, McMoRan privately negotiated the induced conversion of approximately 43,000 shares (49.99% of the total outstanding) of its 8% preferred stock with a liquidation preference of $43.1 million into approximately 6.3 million shares of McMoRan common stock (at a conversion rate equal to 146.1454 shares of common stock per share of 8% preferred stock). To induce the early conversions of these shares of 8% preferred stock, McMoRan paid an aggregate of $8.0 million in cash to the holders of these shares. These holders also received the scheduled dividend on the 8% preferred stock on February 15, 2010. Preferred annual dividend savings following these transactions approximate $3.4 million. Following these transactions, McMoRan has approximately 43,000 shares of its 8% preferred stock outstanding.

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 (6¾% 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 bridge loan (Note 6) that McMoRan used to partially fund its 2007 oil and gas property acquisition (Note 9).

The 6¾% 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 was 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 2008, McMoRan agreed in a privately negotiated transaction to induce conversion of approximately 990,000 shares of its 6¾% preferred stock (approximately 40% of the original issuance), with a liquidation preference of approximately $99 million, into approximately 6.7 million shares of McMoRan common stock (based on the minimum conversion rate of 6.7204 shares of common stock for each share of 6¾% preferred stock). McMoRan paid an aggregate $7.4 million in cash to the holders of these shares to induce the conversion of this 6¾% preferred stock, which is recorded as a $7.4 million charge to preferred dividends in the third quarter of 2008. Preferred dividend payment savings related to this transaction approximate $15 million through the November 2010 mandatory conversion date of the securities. Following this transaction, the remaining outstanding 6¾% preferred stock is convertible into between 10.7 million and 12.8 million shares of McMoRan common stock depending on the price of McMoRan's common stock, subject to anti-dilution adjustments.

In June 2002, McMoRan completed a $35 million public offering of 1.4 million shares of its 5% mandatorily redeemable convertible preferred stock (5% 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. 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% preferred stock was $1.6 million for the year ended December 31, 2007. Dividends paid were $1.1 million for the year ended December 31, 2007.

9. 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 (the 2007 oil and gas property acquisition). MOXY 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 through borrowings under its credit facility and an interim bridge loan facility (Note 6).

The following assumes MOXY acquired the properties effective January 1, 2007, for the period presented (amounts in thousands, except for per share data).

	(Pro Forma, Unaudited) Year Ended December 31, 2007
Revenues	$ 888,550
Operating income	85,163
Net income (loss)	(55,645)
Basic net income (loss) per share of common stock	$(1.62)
Diluted net income (loss) per share of common stock	(1.62)

10. EARNINGS PER SHARE

McMoRan had a net loss from continuing operations for each of the three years in the period ending December 31, 2009. 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% preferred stock, 8% preferred stock, 6¾% preferred stock, 6% notes and 5¼% 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,		
	2009	2008	2007
In-the-money stock options [a, b]	-	1,631	1,727
Shares issuable upon exercise of stock warrants [a, c]	-	257	1,467
Shares issuable upon assumed conversion of:			
8% preferred stock [d]	6,631	-	-
6¾% preferred stock [e]	12,817	17,705	2,525
5¼% notes [f]	4,508	5,508	6,938
6% notes [g]	-	2,635	7,079
5% preferred stock [h]	-	-	3,103

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 pursuant to a prior business transaction 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. The remaining warrant was exercised in June 2008 for 0.76 million common shares in a cashless transaction and received 0.64 million common shares (Note 4).
d. Amount represents total equivalent common stock shares assuming conversion of 8% preferred stock (Note 8). The 2009 amount is reduced from the total 12.6 million equivalent shares that would have been issued upon conversion to reflect the number of days the preferred stock was outstanding in 2009. Preferred dividends totaled $3.6 million in 2009.
e. Amount represents total equivalent common stock shares assuming conversion of 6¾% preferred stock (Note 8). The 2007 amount is reduced from the total 17.4 million equivalent shares that would have been issued upon conversion to reflect the number of days the preferred stock was outstanding in 2007. Preferred dividends, amortization of convertible preferred stock issuance costs and inducement payments for the early conversion of preferred stock totaled $10.7 million in 2009, $22.3 million in 2008 and $2.6 million in 2007.
f. Amount represents total equivalent common stock shares assuming conversion of 5¼% notes (Note 6). Net interest expense on the 5¼% notes totaled $4.0 million in 2009, $4.4 million in 2008 and $6.1 million in 2007.
g. Amount represents total equivalent common stock shares assuming conversion of 6% notes (Note 6). Related net interest expense totaled $1.5 million in 2008 and $6.6 million in 2007.
h. Amount represents total equivalent common stock shares assuming conversion of 5% 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.

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

	Years Ended December 31,		
	2009	2008	2007
Outstanding options (in thousands)	8,271	232	5,281
Average exercise price	$ 15.21	$ 23.83	$ 17.36

11. 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, 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's 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,		
	2009	2008	2007
Accretion and other – sulphur reclamation and contingency obligations	1,863	3,295	1,738
Caretaking costs- Port Sulphur	2,119	979	901
Environmental remediation activities	2,027[a]	-	-
Sulphur retiree costs[b]	(444)	494	(3,155)
General and administrative and legal	324	236	174
Insurance	177	432	463
Other	31	60	(3,948)[c]
(Income) loss from discontinued operations	$ 6,097	5,496	(3,827)

a. Primarily relates to certain environmental remediation activities at the Port Sulphur, Louisiana and Galveston, Texas facilities.
b. Reflects postretirement benefit costs associated with certain retired former sulphur employees (Note 16). The amounts during 2009, 2008 and 2007 reflect reductions of the contractual liability resulting from decreased health care claim costs of $1.1 million, $0.7 million and $4.6 million, respectively.
c. Includes $4.2 million of finalized insurance recoveries associated with the Port Sulphur property damage claims resulting from the 2005 hurricanes.

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 and successor 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, 2009, McMoRan has paid approximately $0.2 million to settle certain claims associated with these assumed historical environmental obligations (Note 16).

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.

12. EMPLOYEE BENEFITS

Stock-Based Awards. At December 31, 2009, McMoRan had eight shareholder-approved stock incentive plans, five of which had shares available for grant. Under each plan McMoRan is authorized to issue a fixed amount of stock-based awards, which include stock options, stock appreciation rights, restricted stock, restricted stock units (RSUs) and other stock-based awards that are issuable in or valued by McMoRan common shares. Below is a summary of McMoRan's plans.

Plan	Authorized amount of stock-based awards	Shares available for grant at December 31, 2009
2008 Stock Incentive Plan (2008 Plan)	5,500,000	2,113,250
2005 Stock Incentive Plan (2005 Plan)	3,500,000	22,750
2004 Director Compensation Plan (2004 Directors Plan)	175,000	40,905
2003 Stock Incentive Plan (2003 Plan)	2,000,000	3,750
2001 Stock Incentive Plan (2001 Plan)	1,250,000	250
2000 Stock Option Plan (2000 Plan)	600,000	-
1998 Stock Option Plan	775,000	-
1998 Stock Option Plan for Non-Employee Directors (Directors Plan)	75,000	-

Restricted Stock Units. Under McMoRan's incentive plans, its Board of Directors granted 20,000 RSUs in 2009, 20,000 RSUs in 2008 and 43,000 RSUs in 2007. The RSUs are converted ratably into an equivalent number of shares of McMoRan common stock on the first three anniversaries of the grant date, except for RSUs granted to the non-management directors, which vest incrementally over the first four anniversaries of the grant date. RSUs converted into common stock totaled 13,861 shares in 2009, 8,232 shares in 2008 and 4,167 shares in 2007. 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 and is charged to expense over the three or four-year vesting period of each respective grant. McMoRan charged approximately $0.3 million of this deferred compensation to expense in 2009, $0.2 million in 2008 and $0.1 million in 2007 and 2006.

Stock Options. McMoRan's Board of Directors grants stock options under its stock incentive plans. Except for certain awards described below, the stock options become exercisable in 25 percent annual increments beginning one year from the date of grant and expire ten years after the date of grant. A summary of stock options outstanding follows:

	2009		2008		2007	
	Number of Options	Average Option Price	Number of Options	Average Option Price	Number of Options	Average Option Price
Beginning of year	9,116,750	$14.91	7,754,100	$14.96	7,095,991	$15.50
Granted	1,855,500	6.46	1,759,500	15.25	1,353,250	12.29
Exercised	-	-	(318,475)	17.90	(213,695)	8.37
Expired/forfeited	(526,000)	15.83	(78,375)	15.29	(481,446)	18.33
End of year	10,446,250	13.37	9,116,750	14.91	7,754,100	14.96
Exercisable at end of year	7,549,500		6,565,437		5,636,100	

The total intrinsic value of options exercised during the years ended December 31, 2008 and 2007 was $4.0 million and $1.0 million, respectively. The weighted average fair value of shares vested during the years ended December 31, 2009, 2008 and 2007 was $11.19, $15.50 and $10.02, respectively. The total intrinsic value of all McMoRan's options outstanding at December 31, 2009 was $13.8 million which have a weighted average life of 7.7 years. The total intrinsic value of exercisable options totaled $5.5 million at December 31, 2009. The exercisable options had a weighted average life of 5.6 years and a weighted average exercise price of $14.23.

The Co-Chairmen of McMoRan's Board of Directors agreed to forgo all cash compensation during each of the three years ended December 31, 2009. In lieu of cash compensation, McMoRan has granted the Co-Chairmen stock options 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 $6.44 per share in February 2009, 400,000 options at an exercise price of $15.04 per share in January 2008 and 400,000 options at an exercise price of $12.23 per share in January 2007. The Co-Chairmen also received additional grants totaling 350,000 stock options in February 2009 and January 2008 and 400,000 stock options in January 2007, all of which vest ratably over a four-year period.

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

	Year Ended December 31,		
	2009	2008	2007
Cost of options awarded to employees (including Directors)	$ 13,152[a]	$ 28,725[a]	$ 12,415[a]
Cost of options awarded to non-employees	696	1,251	630
Cost of restricted stock units	345	247	62
Total stock-based compensation cost	$ 14,193	$ 30,223	$ 13,107

a. Includes $1.6 million, $10.2 million and $2.8 million of compensation charges associated with immediately vested stock options granted to McMoRan's Co-Chairmen in lieu of receiving any cash compensation during 2009, 2008 and 2007, respectively. Also includes $1.1 million, $4.9 million and $1.2 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 during 2009, 2008 and 2007, respectively.

A summary of the classification of stock-based compensation by financial statement line item for the three years in the period ended December 31, 2009 is as follows (in thousands):

	2009	2008	2007
General and administrative expenses	$ 7,162	$ 14,818	$ 6,334
Exploration expenses	6,633	14,376	6,296
Main Pass Energy Hub start-up costs	398	1,029	477
Total stock-based compensation cost	$ 14,193	$ 30,223	$ 13,107

As of December 31, 2009, total compensation cost related to nonvested, approved stock option awards not yet recognized in earnings was approximately $15.7 million, which is expected to be recognized over a weighted average period of one year. The fair value of option awards 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, 2009, 2008 and 2007 are noted in the following table:

	2009	2008	2007
Weighted average fair value of stock options granted[a]	$ 3.97	$ 24.27	$ 6.94
Expected and weighted average volatility	64.88 %	52.3 %	52.2 %
Expected life of options (in years)[a]	6.43	6.41	6.29
Risk-free interest rate	1.87 %	3.04 %	4.76 %

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 2009, 2008 and 2007). The expected life and fair value of stock options on the respective grant dates during the years ended December 31, 2009, 2008 and 2007 are as follows:

	2009	2008	2007
Expected life (in years)	6.77	6.86	6.56
Fair value of stock option on date of grant	$4.04	$25.41	$7.02

On February 1, 2010, McMoRan's Board of Directors granted a total of 1,766,500 stock options to its employees at an exercise price of $15.73 per share, including immediately exercisable options for an aggregate of 445,000 shares, including 400,000 shares, to its Co-Chairmen in lieu of cash compensation in 2010. The remaining options granted vest ratably over a four year period.

Pension Plans and Other Benefits. McMoRan's previous defined benefit pension plan termination was approved by the Internal Revenue Service effective April 14, 2008, and plan assets were liquidated and distributed to participants in 2008.

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, 2009, the health care trend rate used for Other Benefits was 8.1 percent in 2009, decreasing ratably annually until reaching 4.5 percent in 2027. For the year ended December 31, 2008, the health care cost trend rate used for the Other Benefits was 9.0 percent in 2009, decreasing ratably annually until reaching 5.0 percent in 2013. 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	
	2009	2008	2009	2008
Change in benefit obligation:				
Benefit obligation at the beginning of year	$ -	$ (3,779)	$ (4,873)	$ (5,844)
Service cost	-	-	(52)	(48)
Interest cost	-	(62)	(272)	(285)
Actuarial (losses) gains	-	-	(284)	670
Participant contributions	-	-	(186)	(223)
Benefits paid	-	3,841	816	857
Benefit obligation at end of year	-	-	(4,851)	(4,873)
Change in plan assets:				
Fair value of plan assets at beginning of year	-	1,524	-	-
Return on plan assets	-	21	-	-
Employer/participant contributions	-	2,296	816	857
Benefits paid	-	(3,841)	(816)	(857)
Fair value of plan assets at end of year	-	-	-	-
Funded status	$ -	$ -	$ (4,851)	$ (4,873)
Weighted-average assumptions (percent):				
Discount rate	N/A	N/A	5.2%	6.20%
Expected return on plan assets	N/A	N/A	-	-
Rate of compensation increase	N/A	N/A	-	-

Expected benefit payments for McMoRan's other benefits plan total $0.5 million in each of the five years ending December 31, 2014 and a total of $2.0 million during the ensuing five years. The components of net periodic benefit cost for McMoRan's plans follow (in thousands):

	Pension Benefits			Other Benefits		
	2009	2008	2007	2009	2008	2007
Service cost	$ -	$ -	$ -	$ 52	$ 48	$ 26
Interest cost	-	62	214	271	285	330
Return on plan assets	-	(21)	(100)	-	-	-
Amortization of prior service costs	-	-	-	(40)	(40)	(40)
Recognition of net actuarial loss	-	-	-	-	-	71
Net periodic benefit cost	$ -	$ 41	$ 114	$ 283	$ 293	$ 387

Included in accumulated other comprehensive loss at December 31, 2009 (Note 14), are prior service credits of $0.6 million and actuarial losses of $0.2 million that have not been recognized in net periodic benefit costs associated with McMoRan's Other Benefits. The total amount expected to be recognized into net periodic costs in 2010 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 75 percent of their pre-tax compensation, subject to certain limits prescribed by the Internal Revenue Code. McMoRan matches 100 percent of each employees' contribution up to a maximum of 5 percent of each employees' annual basic compensation amount. In this plan, participants exercise control and direct the investment of their contributions and account balances among various investment options. In connection with the termination of its defined benefits plan, McMoRan enhanced the savings plan for substantially all its employees. Pursuant to the enhancements, 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. Participants who were actively employed on January 1, 2009 became fully vested in the matching contributions. Plan participants vest in McMoRan's enhanced contributions upon completing three years of service with McMoRan. For employees whose eligible compensation exceeds certain levels, McMoRan provides an unfunded defined contribution plan. The balance of this liability totaled $1.4 million on December 31, 2009 and 2008.

McMoRan's results of operations reflect charges to expense totaling $1.1 million in 2009 and 2008 and $0.7 million in 2007 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 16).

13. INCOME TAXES

McMoRan has a net deferred tax asset of $415.0 million as of December 31, 2009, resulting from net operating loss carryforwards and other temporary differences related to McMoRan's activities. McMoRan has provided a valuation allowance, including approximately $35.4 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. McMoRan will continue to assess whether or not its deferred tax assets can be recognized based on operating results in future periods. McMoRan has no material uncertain tax positions as of December 31, 2009.

As of December 31, 2009 and 2008, McMoRan had federal tax net operating loss carryforwards (NOL's) of approximately $485.1 million and $329.7 million, respectively, and state tax NOL's of approximately $243.4 million and $244.8 million, respectively. These NOL's are scheduled to expire in varying amounts between tax years 2013 through 2029. The recorded current federal tax benefit of $2.4 million reflects the expected alternative minimum tax (AMT) refund associated with the carryback of the 2009 AMT NOL against previously paid AMT as a result of recently enacted tax legislation.

Federal tax regulations impose certain annual limitations on the utilization of NOL's from prior periods when a defined level of change in the stock ownership of certain shareholders is exceeded. If a corporation has a statutorily defined change of ownership, its ability to use its existing NOL's could be limited by Section 382 of the Internal Revenue Code depending upon the level of future taxable income generated in a given year and other factors. McMoRan has determined that such a change of ownership has occurred, which, depending upon the amounts and timing of future taxable income generated, may limit McMoRan's ability to use its existing NOL's to fully offset taxable income in future periods. 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. Tax periods open to audit for McMoRan primarily include federal and Louisiana income tax returns subsequent to 2005. NOL amounts prior to this time are also subject to audit.

The components of McMoRan's deferred tax assets (liabilities) at December 31, 2009 and 2008 follow (in thousands):

	December 31, 2009	December 31, 2008
Federal and state net operating loss carryforwards	$ 181,120	$ 128,109
Property, plant and equipment	42,000	38,037
Reclamation and shutdown reserves	156,752	155,197
Deferred compensation, postretirement and pension benefits and accrued liabilities	30,158	25,075
Tax credits and other, net	4,954	(3,356)
Less: valuation allowance	(414,984)	(343,062)
Net deferred tax asset	$ -	$ -

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

	2009	2008	2007
Income tax benefit computed at the federal statutory income tax rate	$ 74,701	$ 74,965	$ 20,907
Change in valuation allowance	(71,922)	(78,508)	(20,517)
Other	(334)	1,100	(390)
Federal income tax benefit (provision)	2,445	(2,443)	-
State income tax benefit (provision)	-	(65)	-
Total income tax benefit (provision)	$ 2,445	$ (2,508)	$ -

14. COMPREHENSIVE LOSS

The components of McMoRan's comprehensive loss for 2009, 2008 and 2007 follows (in thousands):

	2009	2008	2007
Net loss	$ (210,986)	$ (216,694)	$ (59,734)
Other comprehensive loss			
Amortization of previously unrecognized pension components, net	(40)	(40)	31
Change in unrecognized net gains/losses of pension plans	(284)	671	589
Comprehensive loss	$ (211,310)	$ (216,063)	$ (59,114)

15. 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 $8.4 million in 2009, $7.5 million in 2008 and $5.5 million in 2007. 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, 2009 and 2008, 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 12).

16. COMMITMENTS AND CONTINGENCIES

Commitments. At December 31, 2009, McMoRan had $260.1 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. Included in this amount is $230.1 million of expenditures for drilling rig contract charges to be expended over approximately the next two years which McMoRan expects to share with its partners in its exploration program.

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 2014 and July 2014, respectively, and office space in Lafayette, Louisiana, which expires in November 2012. At December 31, 2009, McMoRan's total minimum annual contractual charges aggregated $10.3 million, with payments totaling $2.3 million in 2010, 2011 and 2012, $2.2 million in 2013 and $1.2 million in 2014. Rent expense, including rent allocated to McMoRan by FM Services (Note 15), totaled $3.2 million in 2009, $2.8 million in 2008 and $1.1 million in 2007.

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 $5.1 million at December 31, 2009 and $6.1 million at December 31, 2008, including $0.5 million and $0.7 million in current liabilities from discontinued operations, respectively. A third-party actuarial consultant assesses 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 2009 used an initial health care cost trend rate of 7.9 percent in 2010 decreasing ratably to 4.5 percent in 2027. During 2008, the assessment used an initial health care cost trend rate of 8.5 percent in 2009 decreasing ratably to 5.0 percent in 2016. McMoRan applied a discount rate of 8.5 percent at December 31, 2009 and 9.5 percent at December 31, 2008 to the consultant's future cost estimates. McMoRan reduced the liability by $1.1 million and $0.7 million at December 31, 2009 and 2008, respectively, primarily reflecting decreases in future health claim costs resulting from lower than expected actual health claim reimbursements offset by higher health trend costs. Future changes to this estimate resulting from changes in assumptions or actual results varying from projected results will be recorded in earnings.

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, 2009, 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.

McMoRan revises its reclamation and well abandonment estimates recorded at least annually. During 2009 and 2008 these estimates were revised for (1) the inclusion of estimates for new properties; (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; (3) changes in the reclamation costs based on revised estimates of future reclamation work to be performed; and (4) changes in McMoRan's credit-adjusted, risk-free interest rate. McMoRan's credit adjusted, risk-free interest rates ranged from 6.9 percent to 13.1 percent at December 31, 2009, 8.5 percent to 13.1 percent at December 31, 2008 and 8.5 percent to 10.0 percent at December 31, 2007. At December 31, 2009, McMoRan's estimated undiscounted reclamation obligations, including inflation and market risk premiums, totaled $582.2 million, including $43.4 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,		
	2009	2008	2007
Oil and Natural Gas			
Asset retirement obligation at beginning of year	$ 421,201	$ 294,737	$ 25,876
Liabilities settled	(42,212)	(43,782)	(6,720)
Scheduled accretion expense [a]	30,910	32,933	12,222
Reclamation costs assumed from third parties	842	2,859	-
Liabilities assumed in 2007 property acquisition	-	-	267,537
Incurred liabilities	1,869	2,476	272
Revision for changes in estimates	16,101	131,978 [b]	(4,450)
Asset retirement obligations at end of year	$ 428,711	$ 421,201	$ 294,737

	Years Ended December 31,		
	2009	2008	2007
Sulphur			
Asset retirement obligations at beginning of year:	$ 23,003	$ 21,300	$ 23,094
Liabilities settled	(481)	(1,591)	(3,532)[c]
Scheduled accretion expense	2,001	866	1,738
Revision for changes in estimates	2,929	2,428	-
Asset retirement obligation at end of year	$ 27,452	$ 23,003	$ 21,300

a. Accretion expense charges are included within depletion, depreciation and amortization expense in the accompanying consolidated statements of operations.
b. Primarily represents estimated future abandonment costs associated with damaged structures and well abandonment charges related to Hurricane Ike.
c. Amount of costs incurred to remove structures at Port Sulphur that were damaged by hurricanes Katrina and Rita in 2005.

At December 31, 2009, McMoRan had $7.8 million in restricted investments associated with third party prepayments of future abandonment costs and $33.9 million in escrow associated with the funding requirements related to a portion of the reclamation obligations of the 2007 oil and gas property acquisition. McMoRan is required to make payments under these requirements 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. These restricted funds are classified as long-term restricted cash in the accompanying consolidated balance sheets.

Litigation. 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.

17. MAIN PASS ENERGY HUB™ PROJECT

Freeport Energy's long-term business objectives may include the pursuit of alternative uses of its discontinued sulphur facilities at Main Pass in the Gulf of Mexico. Freeport Energy refers to this project as the Main Pass Energy Hub™ project (MPEH™).

The Maritime Administration (MARAD) approved Freeport Energy's license application for the MPEH™ project in January 2007 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 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. Freeport Energy incurred costs for the MPEH™ project totaling $1.6 million in 2009, $6.0 million in 2008 and $9.8 million in 2007.

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. Future financing and commercial arrangements could also reduce Freeport Energy's equity interest in the project. Commercialization of the project has been adversely affected by increased domestic supplies of natural gas, excess LNG re-gasification capacity and general market conditions.

18. 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 U.S. generally accepted accounting principles.

Oil and Gas Capitalized Costs.

	Years Ended December 31, 2009	2008
	(In Thousands)	
Unproved properties [a]	$ 93,584	$ 51,684
Proved properties	2,152,813	2,111,893
Subtotal	2,246,397	2,163,577
Less accumulated depreciation and amortization	(1,450,205)	(1,171,045)
Net oil and gas properties	$ 796,192	$ 992,532

a. Includes costs associated with in-progress wells and wells not fully evaluated, including related leasehold acquisition costs, totaling $62.6 million at December 31, 2009 and $43.8 million at December 31, 2008.

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

	Years Ended December 31, 2009	2008	2007
		(In Thousands)	
Acquisition of properties:			
Proved	$ 78	$ 2,230	$ 1,314,136 [a]
Unproved	-	2,808	8,313 [a]
Exploration costs	148,465	125,039	140,874
Development costs	16,715	126,199	59,287
	$ 165,258	$ 256,276	$ 1,522,610

a. Includes the costs associated with the 2007 oil and gas property acquisition (Note 9), 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, 2009 (in thousands):

	Years Ended December 31, 2009	2008	2007
Beginning of year	$ 43,791	$ 55,980	$ 38,456
Additions to capitalized exploratory well costs pending determination of proved reserves	85,356	141,263	157,216
Reclassifications to wells, facilities, and equipment based on determination of proved reserves	(6,180)	(120,182)	(117,259)
Amounts charged to expense	(60,318)	(33,270)	(22,433)
End of year	$ 62,649	$ 43,791	$ 55,980

At December 31, 2009, one well (South Timbalier Block 168 No. 1) (Blackbeard West) had costs capitalized for a period in excess of one year following the completion of drilling operations. The well was drilled to a total depth of 32,997 feet in October 2008 and logs indicated four potential hydrocarbon bearing zones below 30,067 feet that require further evaluation. The well has been temporarily abandoned while the necessary long-lead time completion equipment was designed and procured for this high pressure test. McMoRan will utilize information gained from other wells in the area to consider the priorities of future operations at Blackbeard West. McMoRan's investment in Blackbeard West totaled $31.6 million at December 31, 2009. There were no well costs capitalized for a period in excess of one year following completion of drilling operations as of December 31, 2008.

Proved Oil and Natural Gas Reserves (Unaudited). The SEC issued its final rule to revise oil and gas reserve estimation and disclosure requirements and McMoRan was required to adopt the provisions of this rule effective December 31, 2009. Proved oil and natural gas reserves for the period ending December 31, 2009 have been estimated by Ryder Scott, L.P. (Ryder Scott), in accordance with the new guidelines established by the SEC as set forth in Rule 4-10 (a) (6), (22), (26) and (31). Proved oil and natural gas reserves for each of the two years in the period ending December 31, 2008 were also estimated by Ryder Scott, in accordance with guidelines established by the SEC that were in effect at that time. 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. Revisions of proved reserves represent changes in previous estimates of proved reserves resulting from new information obtained from production history, additional development drilling and/or changes in other factors, including economic considerations. Discoveries and extensions represent additions to proved reserves resulting from (1) extensions of proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to initial discovery, and (2) discovery of new fields with proved reserves or of new reservoirs of proved reserves in old fields. 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		
	2009	2008	2007	2009	2008	2007
Proved reserves:						
Beginning of year	16,989	19,717	5,772	242,897	245,606	41,202
Revisions of previous estimates	1,369	(335)	565	(12,610)	5,469	(1,039)
Discoveries and extensions	131	1,016	484	4,377	45,993	25,552
Production	(2,970)	(3,633)	(2,385)	(55,842)	(67,891)	(41,147)
Purchase of reserves	-	224	15,281 [a]	-	13,720	221,038 [a]
End of year	15,519 [b]	16,989	19,717	178,822 [b]	242,897	245,606

	Oil			Natural Gas		
	2009	2008	2007	2009	2008	2007
Proved developed reserves:						
Beginning of year	15,039	17,452	5,526	198,610	203,595	34,949
End of year	13,483	15,039	17,452	135,150	198,610	203,595

a. Reflects the estimated proved reserves of the 2007 oil and gas property acquisition (Note 9).
b. At December 31, 2009, McMoRan had natural gas imbalances of 1.1 Bcfe for under deliveries and 1.0 Bcfe for over deliveries which are not reflected in the above reserve quantities.

In January 2010, McMoRan logged 200 net feet of pay in multiple Eocene/Paleocene (Wilcox) sands in its Davy Jones discovery well. The reserve amounts reflected above do not include reserves attributable to the Davy Jones well. McMoRan is currently preparing the well for temporary abandonment pending the delivery and installation of specialized completion equipment. Additional testing (which may require a significant amount of time) will be required to fully assess the extent and classification of reserves to be assigned with respect to this discovery.

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. As of December 31, 2009, the SEC regulations require the use of average prices during the 12-month period prior to December 31, 2009. The weighted average of these prices for all properties with proved reserves was $58.73 per barrel of oil and $4.16 per Mcf of natural gas at December 31, 2009. Prior to December 31, 2009, the SEC regulations required 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 $40.27 per barrel of oil and $6.09 per Mcf of natural gas at December 31, 2008.

	December 31, 2009	December 31, 2008
	(In Thousands)	
Future cash inflows	$ 1,655,260	$ 2,163,814
Future costs applicable to future cash flows:		
Production costs	(519,995)	(537,147)
Development and abandonment costs	(649,940)	(673,715)
Future income taxes	(2,348)	(1,965)
Future net cash flows	482,977	950,987
Discount for estimated timing of net cash flows (10% discount rate)[a]	(134,596)	(245,696)
	$ 348,381	$ 705,291

a. 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, 2009	2008	2007
		(In Thousands)	
Beginning of year	$ 705,291	$ 1,638,266	$ 269,962
Revisions:			
Changes in prices	(183,301)	(534,921)	494,774
Accretion of discount	70,529	163,827	26,996
Change in reserve quantities	15,459	4,204	196,253
Other changes, including revised estimates of development costs and rates of production	(97,269)	(234,425)[a]	(186,238)
Discoveries and extensions, less related costs	2,691	211,492	132,808
Development costs incurred during the year	65,256	50,811	8,559
Change in future income taxes	(324)	179,156	(179,725)
Revenues, less production costs	(229,951)	(800,354)	(353,123)
Purchase of reserves in place	-	27,235	1,228,000[b]
End of year	$ 348,381	$ 705,291	$ 1,638,266

a. Includes $107.6 million of revised reclamation cost estimates related to additional costs associated with properties damaged by Hurricane Ike and accelerated timing of when these costs are expected to be incurred.

b. Reflects the standardized measure of the proved reserves for the 2007 oil and gas property acquisition (Note 9).

19. 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 condensed consolidating financial information includes information regarding McMoRan, as parent, MOXY and its subsidiaries, as guarantors, and Freeport Energy, as the non-guarantor subsidiary. Included are the condensed consolidating balance sheets at December 31, 2009 and 2008 and the related condensed consolidating statements of operations and cash flow for the years ended December 31, 2009, 2008 and 2007, which should be read in conjunction with the notes to these consolidated financial statements:

CONDENSED CONSOLIDATING BALANCE SHEET
December 31, 2009

	Parent	MOXY	Freeport Energy	Eliminations	Consolidated McMoRan
			(In Thousands)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ 16	$ 241,400	$ 2	$ -	$ 241,418
Accounts receivable	-	79,681	-	-	79,681
Inventories	-	47,818	-	-	47,818
Prepaid expenses	2,919	11,538	-	-	14,457
Fair value of derivative contracts	-	8,693	-	-	8,693
Current assets from discontinued operations	-	-	825	-	825
Total current assets	2,935	389,130	827	-	392,892
Property, plant and equipment, net	-	796,192	31	-	796,223
Discontinued sulphur assets	-	-	6,159	-	6,159
Investment in subsidiaries	694,820	-	-	(694,820)	-
Amounts due from affiliates	-	53,173	-	(53,173)	-
Deferred financing costs and other assets	6,374	47,234	-	-	53,608
Total assets	$ 704,129	$ 1,285,729	$ 7,017	$ (747,993)	$ 1,248,882
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)					
Current liabilities:					
Accounts payable	$ 188	$ 66,209	$ 147	$ -	$ 66,544
Accrued liabilities	728	51,217	-	-	51,945
Current portion of oil and gas accrued reclamation costs	-	106,791	-	-	106,791
Other current liabilities	7,698	2,074	-	-	9,772
Current liabilities from discontinued operations	-	-	9,483	-	9,483
Total current liabilities	8,614	226,291	9,630	-	244,535
Long-term debt	374,720	-	-	-	374,720
Amounts due to affiliates	48,977	-	4,196	(53,173)	-
Accrued oil and gas reclamation costs	-	321,920	-	-	321,920
Accrued sulphur reclamation costs	-	-	19,152	-	19,152
Other long-term liabilities	6,010	8,975	7,762	-	22,747
Total liabilities	438,321	557,186	40,740	(53,173)	983,074
Commitments and contingencies					
Stockholders' equity (deficit)	265,808	728,543	(33,723)	(694,820)	265,808
Total liabilities and stockholders' equity (deficit)	$ 704,129	$ 1,285,729	$ 7,017	$ (747,993)	$ 1,248,882

CONDENSED CONSOLIDATING BALANCE SHEET
December 31, 2008

	Parent	MOXY	Freeport Energy (In Thousands)	Eliminations	Consolidated McMoRan
ASSETS					
Current assets:					
Cash and cash equivalents	$ 35	$ 93,442	$ 9	$ -	$ 93,486
Accounts receivable	-	112,684	-	-	112,684
Inventories	-	31,284	-	-	31,284
Prepaid expenses	12,794	1,025	-	-	13,819
Fair value of derivative contracts	-	31,624	-	-	31,624
Current assets from discontinued operations	-	-	516	-	516
Total current assets	12,829	270,059	525	-	283,413
Property, plant and equipment, net	-	992,532	31	-	992,563
Discontinued sulphur assets	-	-	3,012	-	3,012
Investment in subsidiaries	841,882	-	-	(841,882)	-
Amounts due from affiliates		168,004	-	(168,004)	-
Deferred financing costs and other assets	11,122	40,172	-	-	51,294
Total assets	$ 865,833	$ 1,470,767	$ 3,568	$ (1,009,886)	$ 1,330,282
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)					
Current liabilities:					
Accounts payable	$ 512	$ 76,491	$ 6	$ -	$ 77,009
Accrued liabilities	705	88,329	531	-	89,565
Current portion of oil and gas accrued reclamation costs	-	103,550	-	-	103,550
Other current liabilities	6,835	751	-	-	7,586
Current liabilities from discontinued operations	-	-	2,102	-	2,102
Total current liabilities	8,052	269,121	2,639	-	279,812
Long-term debt	374,720	-	-	-	374,720
Amounts due to affiliates	165,011	-	2,993	(168,004)	-
Accrued oil and gas reclamation costs	-	317,651	-	-	317,651
Accrued sulphur reclamation costs	-	-	22,218	-	22,218
Other long-term liabilities	9,027	9,380	8,451	-	26,858
Total liabilities	556,810	596,152	36,301	(168,004)	1,021,259
Commitments and contingencies					
Stockholders' equity (deficit)	309,023	874,615	(32,733)	(841,882)	309,023
Total liabilities and stockholders' equity (deficit)	$ 865,833	$ 1,470,767	$ 3,568	$ (1,009,886)	$ 1,330,282

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
Year Ended December 31, 2009

	Parent	MOXY	Freeport Energy	Eliminations	Consolidated McMoRan
			(In Thousands)		
Revenues:					
Oil and natural gas	$ -	$ 422,976	$ -	$ -	$ 422,976
Service	-	12,459	-	-	12,459
Total revenues	-	435,435	-	-	435,435
Costs and expenses:					
Production and delivery costs	-	193,081	(56)	-	193,025
Depletion, depreciation and amortization	-	313,980	-	-	313,980
Exploration expenses	-	94,281	-	-	94,281
General and administrative expenses	5,749	37,181	24	-	42,954
Gain on oil and gas derivative contracts	-	(17,394)	-	-	(17,394)
Main Pass Energy Hub™ costs	-	-	1,615	-	1,615
Insurance recoveries	-	(24,592)	-	-	(24,592)
Total costs and expenses	5,749	596,537	1,583	-	603,869
Operating loss	(5,749)	(161,102)	(1,583)	-	(168,434)
Interest expense, net	(41,152)	(1,791)	-	-	(42,943)
Equity in earnings (losses) of consolidated subsidiaries	(166,501)	-	-	166,501	-
Other income (expense), net	(29)	4,072	-	-	4,043
Loss from continuing operations before income taxes	(213,431)	(158,821)	(1,583)	166,501	(207,334)
Income tax benefit	2,445	-	-	-	2,445
Loss from continuing operations	(210,986)	(158,821)	(1,583)	166,501	(204,889)
Loss from discontinued operations	-	-	(6,097)	-	(6,097)
Net loss	(210,986)	(158,821)	(7,680)	166,501	(210,986)
Preferred dividends and amortization of convertible preferred stock issuance costs	(14,332)	-	-	-	(14,332)
Net loss applicable to common stock	$ (225,318)	$ (158,821)	$ (7,680)	$ 166,501	$ (225,318)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
Year Ended December 31, 2008

	Parent	MOXY	Freeport Energy	Eliminations	Consolidated McMoRan
			(In Thousands)		
Revenues:					
Oil and natural gas	$ -	$ 1,058,804	$ -	$ -	$ 1,058,804
Service	-	13,678	-	-	13,678
Total revenues	-	1,072,482	-	-	1,072,482
Costs and expenses:					
Production and delivery costs	-	258,504	(54)	-	258,450
Depletion, depreciation and amortization	-	854,798	-	-	854,798
Exploration expenses	-	79,116	-	-	79,116
General and administrative expenses	7,624	41,024	351	-	48,999
Gain on oil and gas derivative contracts	-	(16,303)	-	-	(16,303)
Main Pass Energy Hub™ costs	-	-	6,047	-	6,047
Insurance recoveries and other	-	(3,391)	-	-	(3,391)
Total costs and expenses	7,624	1,213,748	6,344	-	1,227,716
Operating loss	(7,624)	(141,266)	(6,344)	-	(155,234)
Interest expense, net	(43,722)	(7,168)	-	-	(50,890)
Equity in losses of consolidated subsidiaries	(160,205)	-	-	160,205	-
Other income (expense), net	(2,635)	69	-	-	(2,566)
Loss from continuing operations before income taxes	(214,186)	(148,365)	(6,344)	160,205	(208,690)
Income tax expense	(2,508)	-	-	-	(2,508)
Loss from continuing operations	(216,694)	(148,365)	(6,344)	160,205	(211,198)
Loss from discontinued operations	-	-	(5,496)	-	(5,496)
Net loss	(216,694)	(148,365)	(11,840)	160,205	(216,694)
Preferred dividends and amortization of convertible preferred stock issuance costs	(22,286)	-	-	-	(22,286)
Net loss applicable to common stock	$ (238,980)	$ (148,365)	$ (11,840)	$ 160,205	$ (238,980)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
Year Ended December 31, 2007

	Parent	MOXY	Freeport Energy	Eliminations	Consolidated McMoRan
			(In Thousands)		
Revenues:					
Oil and natural gas	$ -	$ 475,250	$ -	$ -	$ 475,250
Service	-	5,917	-	-	5,917
Total revenues	-	481,167	-	-	481,167
Costs and expenses:					
Production and delivery costs	-	122,175	(48)	-	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
Main Pass Energy Hub™ costs	-	-	9,754	-	9,754
Insurance recovery and other	-	(2,338)	-	-	(2,338)
Total costs and expenses	5,264	462,478	9,916	-	477,658
Operating income (loss)	(5,264)	18,689	(9,916)	-	3,509
Interest expense	(49,513)	(16,853)	-	-	(66,366)
Equity in losses of consolidated subsidiaries	(6,464)	-	-	6,464	-
Other income (expense), net	1,507	(2,211)	-	-	(704)
Loss from continuing operations before income taxes	(59,734)	(375)	(9,916)	6,464	(63,561)
Income tax benefit (expense)	-	-	-	-	-
Loss from continuing operations	(59,734)	(375)	(9,916)	6,464	(63,561)
Income from discontinued operations	-	302	3,525	-	3,827
Net 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 loss applicable to common stock	$ (63,906)	$ (73)	$ (6,391)	$ 6,464	$ (63,906)

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOW
Year Ended December 31, 2009

	Parent	MOXY	Freeport Energy	Consolidated McMoRan
		(In Thousands)		
Cash flow from operating activities:				
Net cash provided by continuing operations	$ (148,451)	$ 285,973	$ (629)	$ 136,893
Net cash used in discontinued operations	-	-	(5,728)	(5,728)
Net cash provided by (used in) operating activities	(148,451)	285,973	(6,357)	131,165
Cash flow from investing activities:				
Exploration, development and other capital expenditures	-	(138,015)	-	(138,015)
Net cash used in investing activities	-	(138,015)	-	(138,015)
Cash flow from financing activities:				
Net proceeds from sale of common stock	84,976	-	-	84,976
Net proceeds from sale of preferred stock	83,275	-	-	83,275
Dividends and inducements payments on convertible preferred stock	(13,469)	-	-	(13,469)
Investment from parent	(6,350)	-	6,350	-
Net cash provided by financing activities	148,432	-	6,350	154,782
Net increase (decrease) in cash and cash equivalents	(19)	147,958	(7)	147,932
Cash and cash equivalents at beginning of year	35	93,442	9	93,486
Cash and cash equivalents at end of year	$ 16	$ 241,400	$ 2	$ 241,418

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOW
Year Ended December 31, 2008

	Parent	MOXY	Freeport Energy	Consolidated McMoRan
		(In Thousands)		
Cash flow from operating activities:				
Net cash provided by continuing operations	$ 23,676	$ 603,205	$ 2,778	$ 629,659
Net cash used in discontinued operations	-	-	(6,262)	(6,262)
Net cash provided by (used in) operating activities	23,676	603,205	(3,484)	623,397
Cash flow from investing activities:				
Exploration, development and other capital expenditures	-	(236,383)	-	(236,383)
Acquisition of properties, net	-	(2,826)	-	(2,826)
Net cash used in investing activities	-	(239,209)	-	(239,209)
Cash flow from financing activities:				
Net borrowings under revolving credit facility	-	(274,000)	-	(274,000)
Dividends and inducements payments on convertible preferred stock	(23,565)	-	-	(23,565)
Proceeds from exercise of stock options, warrants and other	4,696	-	-	4,696
Payments for induced conversion of convertible senior notes	(2,663)	-	-	(2,663)
Investment from parent	(2,252)	-	2,252	-
Net cash provided by (used in) financing activities	(23,784)	(274,000)	2,252	(295,532)
Net increase (decrease) in cash and cash equivalents	(108)	89,996	(1,232)	88,656
Cash and cash equivalents at beginning of year	143	3,446	1,241	4,830
Cash and cash equivalents at end of year	$ 35	$ 93,442	$ 9	$ 93,486

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	$ (15,454)	$ 209,648
Net cash provided by (used in) discontinued operations	-	302	(2,312)	(2,010)
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 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

20. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	Revenues	Operating Income (Loss)	Net Loss [a]	Net Loss per Share Basic	Net Loss per Share Diluted
	(In Thousands, Except Per Share Amounts)				
2009					
1st Quarter	$ 97,376	$ (49,139)	$ (63,241)	$ (0.90)	$ (0.90)
2nd Quarter	96,552	(87,258)	(100,612)	(1.40)	(1.40)
3rd Quarter	109,535	(35,514)	(51,932)	(0.60)	(0.60)
4th Quarter	131,972	3,477	(9,533)	(0.11)	(0.11)
	$ 435,435	$ (168,434)	$ (225,318)		

	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)				
2008					
1st Quarter	$ 295,476	$ 55,825	$ 32,009	$ 0.59	$ 0.46
2nd Quarter	375,508	70,256	49,725	0.87	0.63
3rd Quarter	285,245	18,057	(6,132)	(0.10)	(0.10)
4th Quarter	116,253	(299,372)	(314,582)	(4.46)	(4.46)
	$ 1,072,482	$ (155,234)	$ (238,980)		

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).

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-15(e) and 15d-15(e) 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 as of the end of the period covered by this report.

(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.

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. 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. A mixture of hydrocarbons that exists in the gaseous phase at original reservoir tempature and pressure, but that, when produced, is in the liquid phase at surface pressure and tempature.

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 to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another 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 completion 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.

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.

Proved oil and gas reserves. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible-from a given date forward, from known reservoirs, an under existing economic conditions, operating methods, and government regulations-prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonable certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

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.

For additional information regarding the definitions contained in this Glossary, or for other Oil & Gas definitions, please see Rule 4-10 of Regulation S-X.

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 12, 2010.

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 12, 2010.

* 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	Composite Certificate of Incorporation of McMoRan		10-Q	001-07791	08/07/2009
3.2	Amended and Restated By-Laws of McMoRan as amended effective through February 1, 2010		8-K	001-07791	02/03/2010
3.3	Certificate of Elimination of Series A Participating Cumulative preferred Stock of McMoRan		8-K	001-07791	11/14/2008
4.1	Form of Certificate of McMoRan Common Stock		S-4	333-61171	10/06/1998
4.2	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
4.3	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
4.4	Indenture dated October 6, 2004 by and among McMoRan and the Bank of New York, as trustee		8-K	001-07791	10/07/2004
4.5	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
4.6	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
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

Exhibit Number	Exhibit Title	Filed with this Form 10-K	Incorporated by Reference Form	File No.	Date Filed
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	First Amendment to Credit Agreement dated as of June 20, 2008, among McMoRan Exploration Co., as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and the lenders party thereto		10-Q	001-07791	08/07/2008
10.15	Second Amendment to Credit Agreement dated as of September 10, 2008, among McMoRan Exploration Co., as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and the lenders party thereto		10-Q	001-07791	11/06/2008
10.16	Third Amendment to Credit Agreement dated as of April 17, 2009, among McMoRan Exploration Co., as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and the lenders party thereto		10-Q	001-07791	05/11/2009
10.17	Fourth Amendment to Credit Agreement dated as of February 2, 2010, among McMoRan Exploration Co., as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and the lenders party thereto	X			
10.18	Underwriting Agreement dated June 16, 2009 between McMoRan Exploration Co. and J.P. Morgan Securities Inc., as representative of the several underwriters names in Schedule 1 thereto		8-K	001-07791	06/19/2009

Exhibit Number	Exhibit Title	Filed with this Form 10-K	Incorporated by Reference Form	File No.	Date Filed
10.19	Underwriting Agreement dated June 16, 2009 between McMoRan Exploration Co. and J.P. Morgan Securities Inc., as representative of the several underwriters names in Schedule 1 thereto		8-K	001-07791	06/19/2009
10.20*	McMoRan 1998 Stock Option Plan, as amended and restated		10-Q	001-07791	05/10/2007
10.21*	McMoRan 1998 Stock Option Plan for Non-Employee Directors		10-Q	001-07791	05/10/2007
10.22*	McMoRan Form of Notice of Grant of Nonqualified Stock Options under the 1998 Stock Option Plan		10-Q	001-07791	08/04/2005
10.23*	McMoRan 2000 Stock Incentive Plan, as amended and restated		10-Q	001-07791	05/10/2007
10.24*	McMoRan Form of Notice of Grant of Nonqualified Stock Options under the 2000 Stock Incentive Plan		10-Q	001-07791	08/04/2005
10.25*	McMoRan 2001 Stock Incentive Plan, as amended and restated		10-Q	001-07791	05/10/2007
10.26*	McMoRan 2003 Stock Incentive Plan, as amended and restated		10-Q	001-07791	05/10/2007
10.27*	McMoRan's Performance Incentive Awards Program as amended December 1, 2008		10-K	001-07791	02/27/2009
10.28*	McMoRan Form of Notice of Grant of Nonqualified Stock Options under the 2001 Stock Incentive Plan		10-Q	001-07791	08/04/2005
10.29*	McMoRan Form of Restricted Stock Unit Agreement Under the 2001 Stock Incentive Plan		10-Q	001-07791	08/09/2007
10.30*	McMoRan Exploration Co. Executive Services Program, as amended May 4, 2009	X			
10.31*	McMoRan Form of Notice of Grants of Nonqualified Stock Options under the 2003 Stock Incentive Plan		10-Q	001-07791	08/04/2005
10.32*	McMoRan Form of Restricted Stock Unit Agreement Under the 2003 Stock Incentive Plan		10-Q	001-07791	08/09/2007
10.33*	McMoRan 2004 Director Compensation Plan, as amended and restated		10-Q	001-07791	05/10/2007
10.34*	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
10.35*	Amended and Restated Agreement for Consulting Services between FM Services Company and B.M. Rankin, Jr. effective as of January 1, 2010	X	10-K	001-07791	03/25/1999
10.36*	McMoRan Director Compensation		10-Q	001-07791	05/11/2009
10.37*	McMoRan Exploration Co. 2005 Stock Incentive Plan		10-Q	001-07791	05/10/2007
10.38*	Form of Notice of Grant of Nonqualified Stock Options under the 2005 Stock Incentive Plan		8-K	001-07791	05/06/2005
10.39*	Form of Restricted Stock Unit Agreement under the 2005 Stock Incentive Plan		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
10.40*	McMoRan Exploration Co. Supplemental Executive Capital Accumulation Plan		10-Q	001-07791	05/08/2008
10.41*	McMoRan Exploration Co. Supplemental Executive Capital Accumulation Plan Amendment One		10-Q	001-07791	05/08/2008
10.42*	McMoRan Exploration Co. Supplemental Executive Capital Accumulation Plan Amendment Two		10-K	001-07791	02/27/2009
10.43*	McMoRan Exploration Co. 2005 Supplemental Executive Capital Accumulation Plan		10-K	001-07791	02/27/2009
10.44*	McMoRan Exploration Co. 2008 Stock Incentive Plan.		8-K	001-07791	06/11/2008
10.45*	Form of Notice of Grant of Nonqualified Stock Options under the 2008 Stock Incentive Plan.		8-K	001-07791	06/11/2008
10.46*	Form of Restricted Stock Unit Agreement under the 2008 Stock Incentive Plan.		8-K	001-07791	06/11/2008
10.47*	Form of Notice of Grant of Nonqualified Stock Options and Restricted Stock Units under the 2008 Stock Incentive Plan (for grants made to non-management directors and advisory directors)		8-K	001-07791	06/11/2008
10.48*	McMoRan Severance Plan.		10-K	001-07791	02/27/2009
10.49*	Letter Agreement between Nancy Parmelee and FM Services Company (partially allocated to McMoRan Exploration Co.).	X			
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 officers 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			
99.1	Report of Ryder Scott Company, L.P.	X			

* Indicates management contract or compensatory plan or agreement.

Board of Directors

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

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

Robert A. Day[1]
Chairman of the Board and Chief Executive Officer
Trust Company of the West

Gerald J. Ford[1, 3]
Chairman of the Board
Diamond-A Ford Corp.

H. Devon Graham, Jr.[1, 2, 3]
President
R.E. Smith Interests

Suzanne T. Mestayer[1, 2]
Managing Member
Advisean Partners, LLC

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

Board Committees:
[1] Audit
[2] Corporate Personnel
[3] Nominating and Corporate Governance

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

Dr. J. Taylor Wharton
Retired Special Assistant to the President
for Patient Affairs
Retired 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

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

Administration and Finance

John G. Amato
General Counsel

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

Kathleen L. Quirk
Senior Vice President & Treasurer

W. Russell King
Senior Vice President
Federal Government Affairs

William L. Collier, III
Vice President
Communications

Pamela Q. Masson
Vice President
Human Resources and Corporate Administration

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.

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 McMoRan'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

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