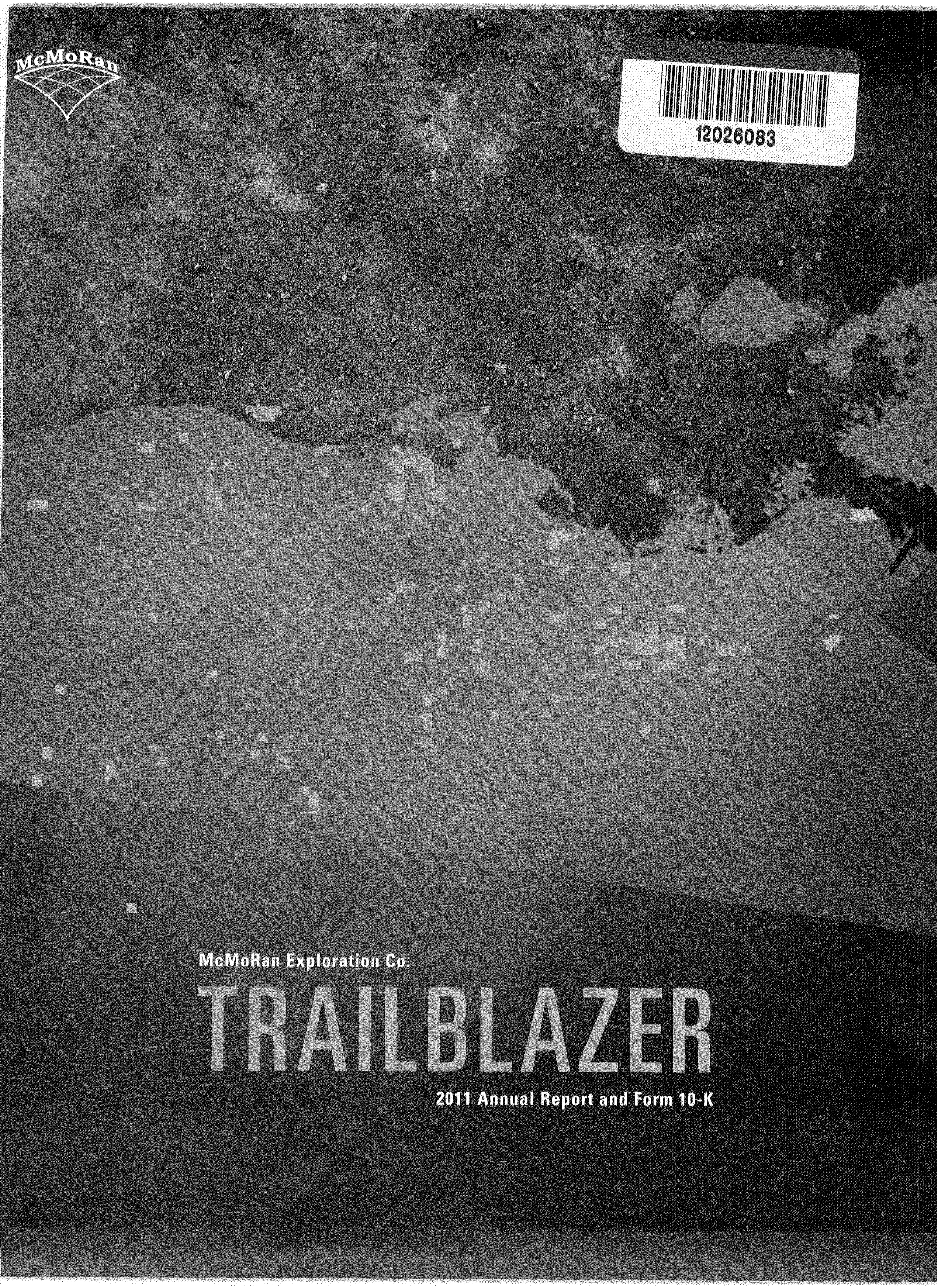
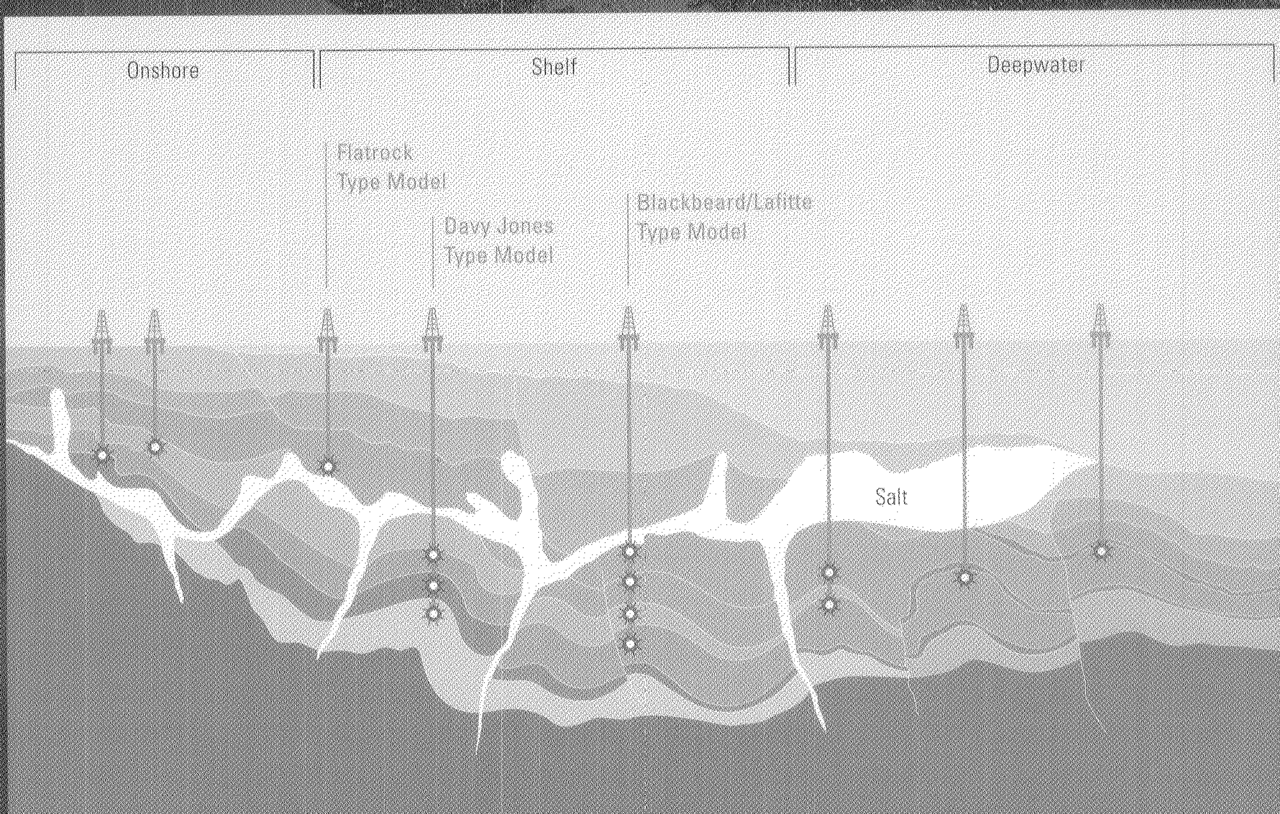


McMoRan Exploration Co.

TRAILBLAZER

2011 Annual Report and Form 10-K

MCMORAN EXPLORATION CO. IS AN INDEPENDENT PUBLIC COMPANY ENGAGED IN THE EXPLORATION, DEVELOPMENT AND PRODUCTION OF NATURAL GAS AND OIL IN THE SHALLOW WATERS OF THE GULF OF MEXICO SHELF AND ONSHORE IN THE GULF COAST AREA.



OUR SHALLOW WATER, ULTRA-DEEP PROSPECTS ON THE SHELF OF THE GULF OF MEXICO TARGET OBJECTIVES BELOW THE SALT WELD AND ARE CORRELATED TO THOSE PRODUCTIVE SECTIONS SEEN ONSHORE AND IN DEEPWATER DISCOVERIES BY OTHER INDUSTRY PARTICIPANTS.

On the cover: McMoRan is one of the largest lease holders on the Shelf of the Gulf of Mexico and the map on the cover highlights our leasehold inventory.

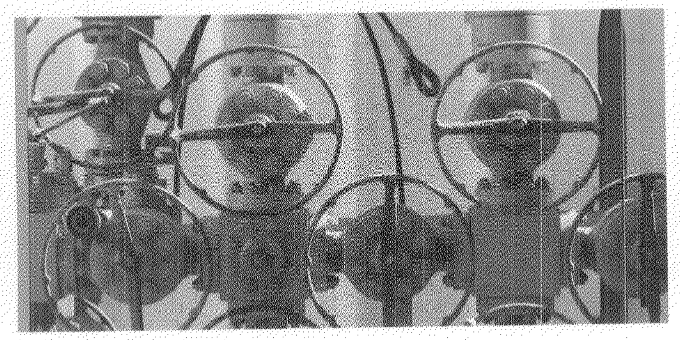
TO OUR SHAREHOLDERS

The title of this year's annual report, "Trailblazer," reflects McMoRan Exploration Co.'s progress in identifying a major new sub-salt geologic trend spanning over 200 miles in the shallow water of the Gulf of Mexico and onshore in the Gulf Coast area. Our geologic success to date has opened up the potential for a multi-Trillion cubic feet (Tcf) natural gas play, called the "Shallow Water, Ultra-Deep," which is attracting significant interest throughout the oil and gas industry.

As a pioneer of this exciting new trend, McMoRan, its partners and its service providers are having to overcome many challenges, including drilling wells deeper than ever drilled before. The challenges include drilling at depths where temperatures are in excess of 400° (F) and with bottom hole pressures exceeding 25,000 pounds per square inch. Logging and other evaluation tools, which are highly reliable in shallower drilling, require new approaches to analyses. In the last four years, we have successfully drilled five wells in the ultra-deep. The drilling data from these wells validates our geologic concept and enhances the potential for additional drilling and development.

Our Davy Jones discovery made in early 2010 was a game-changer and has altered the geologic landscape of the shallow waters of the Gulf of Mexico. The logs and accompanying data on this 20,000-acre closure have provided indications of a major new Wilcox discovery on the mature Gulf of Mexico Shelf. In addition to the Davy Jones discovery, we have announced discoveries at the Davy Jones Offset, and our Blackbeard West, Blackbeard East and Lafitte prospects. These discoveries provide opportunities to test seven sub-salt geologic formations, in addition to the Wilcox, including the Miocene, Frio, Vicksburg, Upper Eocene, Sparta Carbonate, Tuscaloosa and Cretaceous Carbonate. These formations

> *OUR GEOLOGIC SUCCESS TO DATE HAS OPENED UP THE POTENTIAL FOR A MULTI-TCF NATURAL GAS PLAY, CALLED THE "SHALLOW WATER, ULTRA-DEEP," WHICH IS ATTRACTING SIGNIFICANT INTEREST THROUGHOUT THE OIL AND GAS INDUSTRY.*

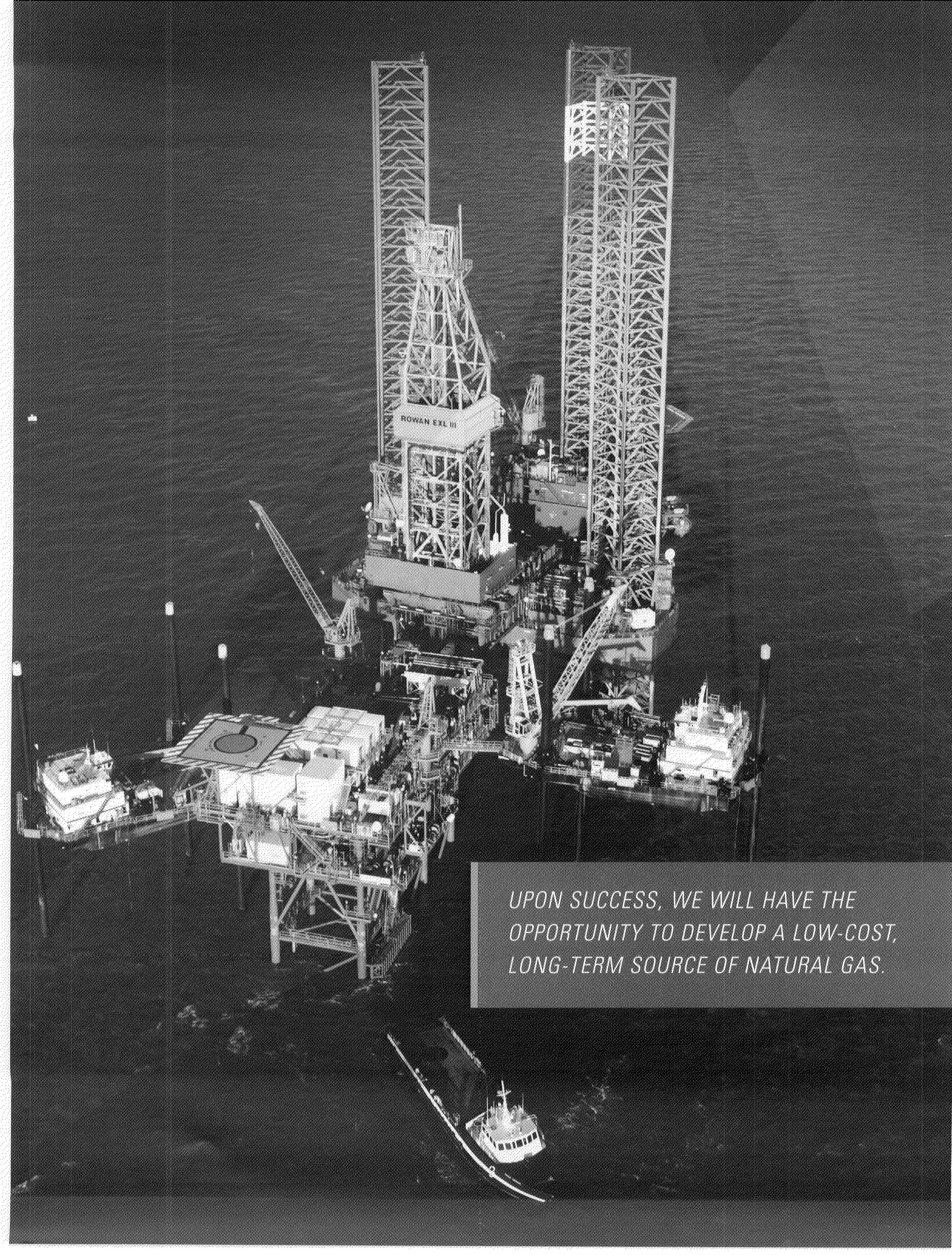


have been prolific onshore, in the deepwater Gulf of Mexico and in international locations.

We are now working to establish commercial production from our success — starting with the Davy Jones No. 1 well, which would be the first commercial well from the shallow water, ultra-deep play. Since the Davy Jones discovery, we have worked to develop the equipment and processes necessary to produce these deep wells in a high temperature and high pressure environment. Flow testing activities for Davy Jones No. 1 began in March 2012 and are in progress as we write this letter.

SHALLOW WATER, ULTRA-DEEP FINDINGS TO DATE

		Davy Jones No. 1	Davy Jones No. 2	Blackbeard West No.1	Blackbeard East	Lafitte
Working Interest		63.4%	63.4%	69.4%	72.0%	72.0%
Net Revenue Interest		50.2%	50.2%	56.5%	57.4%	58.3%
Miocene	Upper				✓	
	Middle			✓	✓	✓
	Lower			✓		✓
Oligocene	Frio				✓	✓
	Vicksburg				✓	
Eocene	Upper					✓
	Sparta Carbonate			NOT REACHED	✓	✓
Paleocene	Wilcox	✓	✓			
Cretaceous	Tuscaloosa	NOT REACHED	✓		NOT REACHED	NOT REACHED
	Lower Carbonate		✓			
Drilled to:		29,000′	30,546′	32,997′	33,318′	34,162′



UPON SUCCESS, WE WILL HAVE THE OPPORTUNITY TO DEVELOP A LOW-COST, LONG-TERM SOURCE OF NATURAL GAS.

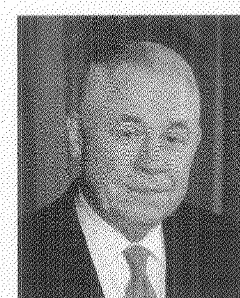
We have made great progress in advancing and de-risking the geological prospectivity of the ultra-deep trend. The next step is to establish commercial production at these depths and temperatures. Upon success, we will have the opportunity to develop a low-cost, long-term source of natural gas in the shallow waters of the Gulf of Mexico and onshore in the Gulf Coast region.

We sincerely appreciate our Board of Directors, Advisory Directors, employees and contractors for their hard work, commitment and support. We are enthusiastic that our exploration results to date have confirmed our geologic model. We look forward to reporting on our progress in 2012 and beyond, as we blaze the trail on this new "shallow water, ultra-deep" trend.

Warmest Regards,

James R. Moffett
Co-Chairman of the Board,
President & Chief Executive Officer

Richard C. Adkerson
Co-Chairman of the Board



March 30, 2012

McMoRan EXPLORATION CO.
2011 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, 2011
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

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 common stock held by non-affiliates of the registrant was approximately $1.4 billion on February 15, 2012, and approximately $1.8 billion on June 30, 2011.

On February 15, 2012, there were outstanding 161,536,663 shares of the registrant's common stock and on June 30, 2011, there were outstanding 158,483,158 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of our Proxy Statement for our 2012 Annual Meeting to be held on June 14, 2012 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, 2011

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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 92.

BUSINESS

McMoRan Exploration Co. was incorporated under the laws of the State of Delaware in 1998. We engage in the exploration, development and production of oil and natural gas in the shallow waters (less than 500 feet of water) of 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. We have rights to approximately 886,000 gross acres, including over 286,000 gross acres associated with the ultra-deep gas play below the salt weld. Our focused strategy enables us to make efficient use of our geological, engineering and operational expertise in these areas where we have more than 40 years of 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.

Our technical and operational expertise is primarily in the Gulf of Mexico and onshore in the Gulf Coast area. 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 generally 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 productive sections encountered onshore, in deepwater and in international locations discovered by other industry participants. When we find commercially exploitable oil or natural gas, a significant advantage to our exploration strategy is that substantial infrastructure already exists in our focus area to support the production and delivery of product. 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 69 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 of expertise. 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 of each exploratory and development opportunity;

- utilizing advanced seismic applications in combination with traditional analysis;
- employing professionals with special geophysical, geological and reservoir assessment expertise in our regions of focus;
- using new technology applications in drilling and completion practices;
- acquiring additional lease acreage, when available on commercially reasonable terms, to complement and/or enhance our investment opportunities and better align them with our overall business strategy; 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.

On December 30, 2010, we completed the acquisition of Plains Exploration & Production Company's (PXP) shallow water Gulf of Mexico shelf assets (PXP Acquisition). Under the terms of the transaction, we issued 51 million shares of common stock and paid $75.0 million cash to PXP. Total consideration for the transaction was approximately $1 billion based on the value of our common stock on the closing date. Concurrent with the PXP Acquisition, in separate private placement transactions we issued $700 million of 5.75% Convertible Perpetual Preferred Stock (5.75% preferred stock) and $200 million of 4% Convertible Senior Notes (4% senior notes) to certain investors. Freeport-McMoRan Copper & Gold Inc. purchased $500 million of the 5.75% preferred stock and the remaining $400 million of convertible securities were purchased by institutional investors (Notes 2, 6 and 8).

The PXP Acquisition increased our scale of operations on the Gulf of Mexico shelf, consolidated our ownership in core focus areas, expanded our participation in future production from our deep gas and ultra-deep exploration and development programs and increased our reserves and production. In addition, we expect to continue to benefit from our positive relationship with PXP through PXP's significant shareholding position in our company, including by having two PXP nominees serve on our expanded board of directors.

Although we do not budget for acquisitions, we continually evaluate acquisition opportunities. The availability, timing and size of acquisitions are unpredictable and future acquisition opportunities could fully utilize or even exceed our existing capital resources. If acquisition opportunities are presented to us, we would consider various funding sources to provide capital if needed, as we have in the past.

Our capital spending is subject to change, depending on drilling results, follow-on development activities, and general market factors 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 results 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.

PROPERTIES

Oil and Gas 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, 2011 totaled 255.8 Bcfe, of which 59 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 regulations 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 who is 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 has over 40 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 our Senior Vice President of Reservoir Engineering, who has over 25 years of technical experience in petroleum engineering and reservoir evaluation and analysis. This individual, who has a Bachelor of Science degree in Petroleum Engineering and a Masters degree in Business Administration, directs 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, 2011. The reserve volumes were determined using the methods prescribed by the SEC, which 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 Natural Gas Liquids (MBbls)	Total (Bcfe)
Proved developed:			
Producing	38,036	5,565	71.4
Non-producing	80,543	9,782	139.3
Shut-in	5,047	226	6.4
Total proved developed	123,626	15,573	217.1
Proved undeveloped	28,425	1,716	38.7
Total proved reserves	152,051	17,289 [a]	255.8

a. Includes 2,848 MBbls of natural gas liquids (NGL's).

Our proved undeveloped reserves are 15 percent of our total proved reserves as of December 31, 2011. As of December 31, 2011, with the exception of one property with 2.5 Bcfe of proved undeveloped reserves, 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 (including the property referred to above) have ongoing production from currently developed zones. The following table represents a summary of activity within our proved undeveloped reserve category for the years ended December 31, 2011 and 2010:

	2011	2010
Proved undeveloped reserves (MMcfe):		
Beginning of year	54,952	55,883
Transferred to "proved developed" through drilling	(3,795)	(5,276)
Increase (decrease) due to evaluation reassessments and drilling results, net	(12,435)	(4,867)
Acquisition of reserves	-	9,212
Reductions of proved undeveloped reserves aged five or more years	-	-
End of year	38,722	54,952

During 2011, we incurred capital expenditures of approximately $13.1 million for the development of the Laphroaig No. 2 well which initiated production in the second quarter of 2011 resulting in the reclassification of approximately 3.8 Bcfe of net reserves from the proved undeveloped to the proved developed producing categories. We also incurred approximately $37.1 million in capital expenditures for the Brazos A-23 development well, the evaluation of which resulted in a reduction of approximately 8.0 Bcfe of proved undeveloped reserves. In addition, in the first quarter of 2011 a reduction of approximately 6.1 Bcfe of proved undeveloped reserves for the West Cameron 294 property resulted following unsuccessful attempts to achieve an economically acceptable farm-out arrangement with a third party for development of the property.

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, 2011 (in thousands).

	Proved Reserves		
	Developed	Undeveloped	Total
Estimated undiscounted future net cash flows before income taxes	$ 1,046,133	$ 120,662	$ 1,166,795
Present value of estimated future net cash flows before income taxes (PV-10) [a, b]	$ 771,323	$ 57,508	$ 828,831
Discounted future income taxes			-
Standardized measure of discounted net cash flows			$ 828,831

a. Calculated based on the twelve month average prices during 2011 and costs prevailing at December 31, 2011 and using a 10 percent per annum discount rate as required by the SEC. The weighted average prices for all properties with proved reserves was $100.68 per barrel of oil, $56.82 per barrel of NGLs and $4.29 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 17).

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, 2011 rather than monthly average prices specified by SEC rules. Based on this forward price curve, natural gas average realizations were $4.72 per Mcf, oil average realizations were $98.03 per barrel, and average natural gas liquids' realizations were $55.24 per barrel over the life of the properties.

	Gas (MMcf)	Oil and NGLs (MBbls)	Total (Bcfe)	PV-10 (in millions)[a]
NYMEX price scenario	151,830	17,169	254.8	$ 816

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 187 MMcfe/d in 2011, 161 MMcfe/d in 2010 and 202 MMcfe/d in 2009.

The following table shows production volumes, average sales prices and average production (lifting) costs for our oil, natural gas and NGLs 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,		
	2011	2010	2009
Natural gas production (Mcf)	45,000,000	38,019,100	50,081,900
Crude oil and condensate production, excluding Main Pass Block 299 (Bbls)	2,360,000	2,122,100	2,474,400
Crude oil production from Main Pass Block 299 (Bbls)	348,110	375,600	495,500
NGL production (Mcf equivalent)	6,925,400	5,956,700	5,759,600
Average sales prices:			
Natural gas (per Mcf)	$ 4.32	$ 4.77	$ 4.22
Crude oil and condensate, excluding Main Pass Block 299 (per Bbl)	104.86	78.70	60.19
Crude oil and condensate, Main Pass Block 299 (per Bbl)	101.75	73.41	60.35
NGLs (per Mcf equivalent)	9.13	7.32	5.43
Production (lifting) costs: [a]			
Per barrel for Main Pass Block 299 [b]	$97.83	$51.94	$38.15
Per Mcfe for other properties [c]	2.62	2.89	2.47

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, cost and complexity of workover activities 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 Block 299 are higher than the production costs for our other properties primarily because of the sour crude oil that is produced at Main Pass Block 299. Production costs for Main Pass Block 299 included workover expenses of approximately $16.2 million or $46.64 per barrel in 2011, $1.9 million or $5.18 per barrel in 2010 and $1.0 million or $1.95 per barrel in 2009.
c. Production costs were converted to an Mcf equivalent on the basis of one barrel of oil and/or NGL being equivalent to six Mcf of natural gas. Production costs included workover expenses totaling

$37.6 million or $0.57 per Mcfe in 2011, $27.9 million or $0.49 per Mcfe in 2010 and $31.2 million or $0.44 per Mcfe in 2009.

Acreage. We own or control interests in 951 oil and gas leases in the Gulf of Mexico and onshore Louisiana and Texas covering approximately 886,000 gross acres (556,000 acres net to our interests). Our acreage position includes 687,000 gross acres (430,000 acres net to our interests) located on the outer continental shelf of the Gulf of Mexico. This acreage position includes 286,000 gross acres associated with our ultra-deep gas play. Approximately 43,000 net acres owned by us are scheduled to expire in 2012.

The following table shows the oil and gas acreage in which we held interests as of December 31, 2011. The table does not account for our gross acres associated with our farm-in, or certain other farm-out arrangements.

	Developed		Undeveloped	
	Gross Acres	Net Acres	Gross Acres	Net Acres
Offshore (federal waters)	443,486	263,131	243,805	166,517
Onshore Louisiana and Texas	43,417	23,567	100,902	50,879
Total at December 31, 2011	486,903	286,698	344,707	217,396

Oil and Gas Properties. Our properties are primarily located on the outer continental shelf in the shallow waters (less than 500 feet of water) of the Gulf of Mexico and onshore in the Gulf Coast area of the United States. 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 with 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. Prospects with drilling depths below the salt weld (generally at depths exceeding 25,000 feet) are considered ultra-deep shelf prospects. We focus our exploration activities almost exclusively on deep shelf and ultra-deep shelf prospects.

The following table identifies our top ten producing properties, based on average daily production, as of December 31, 2011.

	Working Interest	Net Revenue Interest	Water Depth	Production [a]	
				Gross	Net
	(%)	(%)	(feet)	(MMcfe/d)	
Deep Shelf:					
South Marsh Island Block 212					
"Flatrock"	55.0	38.8-41.3	10	147	60
"Laphroaig" [b]	37.3-38.4	28.5-29.5	<10	51	15
Louisiana State Lease 18090					
"Long Point"	37.5	26.7	8	25	7
Traditional Shelf: [b]					
Eugene Island Block 251[c]	56.9	19.4-43.9	160	19	9
High Island 537	60.9-74.9	51.0-62.7	200	12	7
Breton Sound 33	37.1	28.4	14	16	5
Vermillion 215	92.0	76.8	122	7	5
Main Pass Block 299	100.0	77.1-83.3	210	5	5
West Delta 27 [d]	62.0	50.1	23	7	4
South Timbalier 193	62.8	46.8-53.0	121	6	3

a. Reflects average daily production rates for the fourth quarter of 2011.
b. We operate these properties with the exception of Breton Sound 33.
c. One well in this property has a 19.4% net revenue interest due to a third party's overriding royalty interest.

d. This property has unitized production and multiple non-unit wells with varying ownership interests of 50.0-75.0% working interest and 41.2-62.0% net revenue interest. The unitized interest is reflected in this table.

Ultra-Deep Shelf. We currently have no production or proved reserves attributable to our ultra-deep shelf prospects to date (see "Oil and Gas Activities" below). We have identified a series of additional prospects within the play and continue to generate additional exploration opportunities on our ultra-deep shelf acreage position where we hold rights to approximately 286,000 gross acres.

Oil and Gas Activities.

Shallow Water Ultra-Deep Exploration and Development Activities. Since 2008, we have actively pursued large ultra-deep targets located in the shallow waters of the Gulf of Mexico (GOM) below the salt weld (i.e. listric fault) at depths generally below 25,000 feet. The data gained to date from five wells confirm our geologic model and the highly prospective nature of this emerging geologic trend. Prior to our involvement in the ultra-deep, there had been only two wells drilled on the Shelf targeting these objectives; one did not reach its targeted depth and the other was outside our focus area. Our results to date have indicated the potential for large accumulations of hydrocarbons at these deeper depths in the shallow waters of the GOM.

Our activities to date have confirmed that drilling below the salt weld on the Shelf of the GOM can be achieved safely. In addition, the data indicate the presence below the salt weld of geologic formations including Middle/Lower Miocene, Wilcox, Frio, Tuscaloosa, Cretaceous carbonate and Sparta carbonate. These formations have been prolific onshore, in the deepwater GOM and in international locations. We intend to conduct further drilling and flow testing to determine the ultimate potential of this emerging geologic trend.

Davy Jones

Completion activities of the Davy Jones No. 1 discovery well at South Marsh Island Block 230 are in an advanced stage with completion and flow testing expected in the first quarter of 2012. Remaining steps include running perforating guns and production tubing in the hole, removing the blowout preventers and installing the production tree prior to flow testing the well. A successful flow test would have important implications on potential future reserve additions at Davy Jones and our other ultra-deep prospects. If the flow test is successful, we expect first production from the well could be established shortly after the flow test.

As previously reported, we have drilled two successful sub-salt wells in the Davy Jones field. The Davy Jones No. 1 well logged 200 net feet of pay in multiple Wilcox sands, which were all full to base. The Davy Jones offset appraisal well (Davy Jones No. 2), which is located two and a half miles southwest of Davy Jones No. 1, confirmed 120 net feet of pay in multiple Wilcox sands, indicating continuity across the major structural features of the Davy Jones prospect, and also encountered 192 net feet of potential hydrocarbons in the Tuscaloosa and Lower Cretaceous carbonate sections. We expect to complete and flow test both wells in 2012.

Davy Jones involves a large ultra-deep structure encompassing four OCS lease blocks (20,000 acres). We hold a 63.4 percent working interest and a 50.2 percent net revenue interest in Davy Jones. Our total investment in Davy Jones, which includes $474.8 million in allocated property acquisition costs, totaled $774.8 million at December 31, 2011.

Blackbeard East

In January 2012, the Blackbeard East ultra-deep exploration by-pass well was drilled to a total depth of 33,318 feet true vertical depth (TVD). Analysis of wireline logs, conventional core samples and sonic logs in January 2012 indicated that the Blackbeard East well encountered potential hydrocarbons in the Sparta carbonate section of the Eocene and Vicksburg section of the Oligocene. The Sparta interval measures 300 feet thick and appears to be a hydrocarbon bearing fractured carbonate. The Vicksburg sand is credited with 10 net feet of pay over a 40 foot gross interval. Flow testing will be required to confirm the potential hydrocarbons and flow rates from these limestone and sandstone formations. A production liner has been set to total depth and the well has been temporarily abandoned while development options are evaluated.

These new intervals are in addition to the 178 net feet of hydrocarbons previously announced above 25,000 feet in the Miocene and the hydrocarbon bearing sands in the Oligocene (Frio) with good porosity below 30,000 feet. Pressure and temperature data below the salt weld between 19,500 feet and 24,600 feet at Blackbeard East indicate that a completion at these depths could utilize conventional equipment and technologies. Blackbeard East is located in 80 feet of water on South Timbalier Block 144. We hold a 72.0 percent working interest and a 57.4 percent net revenue interest in the well. Our total investment in Blackbeard East, which includes $130.5 million in allocated property acquisition costs, totaled $276.9 million at December 31, 2011.

Lafitte

The Lafitte ultra-deep exploration well, which is located on Eugene Island Block 223 in 140 feet of water, commenced drilling on October 3, 2010. The Lafitte well is currently drilling below 33,800 feet TVD with a proposed total depth of 34,000 feet to evaluate additional Oligocene and potential Eocene objectives. In January 2012, wireline logs indicated 40 feet of possible hydrocarbon-bearing Frio sands between 31,300 and 31,700 feet TVD. In November 2011, wirleine logs indicated 56 net feet of hydrocarbon-bearing sand over a 58 foot gross interval in the Cris-R section of the Lower Miocene. Recent pressure data and rotary sidewall cores obtained in the Cris-R sand are being evaluated. The new Frio and Cris-R sand intervals, combined with the 115 feet of potential net Miocene pay previously announced, brings the total possible productive net sands to 211 feet in the Lafitte well.

We are considering delineation drilling opportunities on the Lafitte structure to evaluate this prospect further. We control approximately 15,000 gross acres in the immediate area of Lafitte. The discovery of possible productive sands from our activities to date at Lafitte may be an indicator of the potential of our other acreage in the Lafitte strategic area, including our Barataria and Captain Blood ultra-deep prospects. Barataria (10,000 gross acres) is located west-southwest of Lafitte and Captain Blood (10,000 gross acres) is located immediately south of Lafitte. Our total investment in Lafitte, which includes $35.8 million in allocated property acquisition costs, totaled $160.9 million at December 31, 2011.

Blackbeard West Unit

The Blackbeard West No. 1 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 requiring further evaluation. The well has been temporarily abandoned while we evaluate whether to drill deeper or complete the well to test the existing zones. Our investment in the Blackbeard West No. 1 drilling costs approximated $31.3 million at December 31, 2011.

The Blackbeard West No. 2 ultra-deep exploration well commenced drilling on November 25, 2011 and is currently drilling below 17,650 feet towards a proposed total depth of 26,000 feet. The well, which is located on Ship Shoal Block 188 within the Blackbeard West unit, is targeting Miocene aged sands seen below the salt weld approximately 13 miles east at Blackbeard East. McMoRan holds a 69.4 percent working interest and a 53.1 percent net revenue interest in Ship Shoal Block 188. McMoRan's investment in the Blackbeard West No. 2 well totaled $10.9 million at December 31, 2011. In addition, McMoRan has approximately $27.6 million of leasehold costs for the Blackbeard West unit resulting from allocated property acquisition costs.

Lineham Creek

Operations commenced on December 31, 2011 at the Lineham Creek exploration prospect, which is located onshore in Cameron Parish, Louisiana. The well is currently drilling below 4,600 feet towards a proposed total depth of 29,000 feet and is targeting Eocene and Paleocene objectives below the salt weld. Chevron U.S.A Inc., as operator of the well, holds a 50 percent working interest. McMoRan is participating for a 36.0 percent working interest. Our investment in Lineham Creek totaled $10.4 million at December 31, 2011.

Shallow Water Deep Gas Exploration and Development Activities. In addition to the ultra-deep play on the Shelf of the GOM, our exploration strategy is also focused on the "deep gas play." Deep gas prospects target large Miocene age deposits above the salt weld (i.e. listric fault) at depths typically between 15,000 to 25,000 feet.

Hurricane Deep

The Hurricane Deep well, which is located in 12 feet of water on South Marsh Island Block 217, was drilled to a TVD of 21,378 feet in July 2011. Log results indicated the presence of Operc and Gyro sands that McMoRan determined could be pursued in an updip location. The well has been temporarily abandoned to preserve the wellbore and McMoRan is evaluating opportunities to sidetrack or deepen. McMoRan's total investment in Hurricane Deep, which includes $16.8 million in allocated property acquisition costs, totaled $48.4 million at December 31, 2011.

Boudin

The Boudin deep gas exploration well, which is located in 20 feet of water on Eugene Island Block 26, commenced drilling on February 27, 2011. The well was drilled to a total depth of 24,284 feet. Drilling results indicate potential hydrocarbon bearing zones within a laminated sand section in the Rob-L. The well has been temporarily abandoned while completion alternatives are evaluated. We hold a 53.5 percent working interest and a 42.4 percent net revenue interest in Boudin. Our total investment in Boudin, which includes $14.8 million in allocated property acquisition costs, totaled $55.2 million at December 31, 2011.

Production. We expect production to average approximately 155 MMcfe/d in the first quarter of 2012 and 130 MMcfe/d for the year. This estimate does not include any potential production from Davy Jones. Our estimated production rates are dependent on the timing and success of development drilling, planned recompletions, production performance, weather and other factors.

Capital Expenditures. Depending on drilling results, follow on development opportunities and general market factors, we expect 2012 capital expenditures to approximate $500 million, including $300 million for exploration and $200 million for development. Capital spending will continue to be driven by opportunities.

Reclamation Expenditures. We plan to spend approximately $60 million in 2012 for the abandonment and removal of oil and gas structures in the Gulf of Mexico.

Exploratory and Development Drilling. The following table shows the gross and net number of productive and dry and total exploratory and development wells that we drilled in each of the periods presented.

	2011[a]		2010[a]		2009	
	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Productive	-	-	-	-	1	0.3
Dry	-	-	1	0.5	4	1.4
Total	-	-	1	0.5	5	1.7
Development						
Productive	2	1.4	2	1.7	-	-
Dry	-	-	-	-	-	-
Total	2	1.4	2	1.7	-	-

a. Excludes 8 gross (5.3 net) in-progress wells at December 31, 2011 and 7 gross (4.2 net) in-progress wells at December 31, 2010.

Productive Well Interests. The following table shows our interest in productive oil and natural gas wells as of December 31, 2011. 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 gross wells multiplied by the percentage working interest and/or operating right owned.

	Gas		Oil	
	Gross	Net	Gross	Net
Offshore	103	43.3	71	46.1
Onshore	27	9.8	6	1.7
Total	130	53.1	77	47.8

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 (see "North American Natural Gas and Oil Market Environment" in Items 7. and 7A.). We have previously 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 oil and natural gas derivative contracts.

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 hydrocarbon commodities storage and handling operation. The MPEH™ project is located at our Main Pass facilities located offshore in the Gulf of Mexico, 38 miles east of Venice, Louisiana.

We obtained a license covering the potential use of the facility for the import of liquefied natural gas (LNG) in early 2007; this license expired in 2012. Commercialization of the project was adversely affected by increased domestic supplies of natural gas, excess LNG regasification capacity and general market conditions. McMoRan continues to evaluate other potential commercial options including the use of the MPEH™ assets for handling and storage of various hydrocarbon commodities. 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.

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, 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, 2011, we have interests in 164 offshore leases located in federal waters on the Gulf of Mexico's outer continental shelf. Federal offshore leases are administered by the Bureau of Ocean Energy Management (BOEM). These leases were obtained through competitive bidding, contain relatively standard terms and require compliance with detailed BOEM regulations, Bureau of Safety and Environmental Enforcement (BSEE) regulations and the Outer Continental Shelf Lands Act (OCSLA), which are subject to interpretation and change. Lessees must obtain BOEM 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 and the Environmental Protection Agency. BSEE 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, including regulations to safeguard against or respond to well blowouts and other catastrophes. BSEE regulations also restrict the flaring or venting of natural gas and prohibit the flaring of liquid hydrocarbons and oil without prior authorization.

BSEE has regulations governing the plugging and abandonment of wells located offshore and the installation and removal of all fixed drilling and production facilities. BSEE generally requires that lessees either have substantial net worth, post supplemental bonds or provide 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 BSEE by providing financial assurances from MOXY. We and our subsidiaries' ongoing compliance with applicable BSEE requirements will be subject to meeting certain financial and other criteria. Under some circumstances, BSEE 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 also 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 OCSLA. 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, 2011, we had a total of 119 employees located at our New Orleans, Louisiana headquarters and our Houston, Texas and Lafayette, Louisiana offices. These employees are primarily devoted to production, regulatory matters, 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 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 by any of our directors and executive officers.

COMPETITION

The oil and natural gas industry is highly competitive, particularly with respect to the hiring and retention of technical personnel, the acquisition of leases, interests and other properties and access to drilling rigs and other services in the Gulf of Mexico and Gulf Coast areas. Our competitors include major integrated oil and gas companies and numerous independent oil and gas companies, individual producers and operators. Many of our competitors have financial and other resources substantially greater than ours and from a competitive standpoint may be better positioned to adapt to an increasingly burdensome regulatory environment in response to the *Deepwater Horizon* or other catastrophic events and uncertainties. Our ability to acquire additional oil and natural gas properties and to discover reserves in the future will depend upon our ability to evaluate and select suitable properties and consummate transactions in a highly competitive environment. For more information see Item 1A. Risk Factors.

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 facts, such as those statements regarding potential oil and gas discoveries, oil and gas exploration, development and production activities and costs, capital expenditures, reclamation, indemnification and environmental obligations and costs, potential quarterly and annual production and flow rates, reserve estimates, projected operating cash flows and liquidity, and statements about the potential opportunities and benefits presented by the recent property acquisition, including expectations regarding reserve estimates and production rates. The words "anticipates," "may," "can," "plans," "believes," "estimates," "expects," "projects," "intends," "likely," "will," "should," "to be," and any similar expressions and/or statements that are not historical facts are intended to identify those assertions as forward-looking statements.

We caution readers that forward-looking statements are not guarantees of future performance or exploration and development success, and our actual exploration experience and future financial results may differ materially from those anticipated, projected or assumed in the forward-looking statements. Important factors that may cause our actual results to differ materially from those anticipated by the forward-looking statements include, but are not limited to, those associated with general economic and business conditions, failure to realize expected value creation from acquired properties, variations in the market demand for, and prices of, oil and natural gas, drilling results, unanticipated fluctuations in flow rates of producing wells due to mechanical or operational issues (including those experienced at wells operated by third parties where we are a participant), changes in oil and natural gas reserve expectations, the potential adoption of new governmental regulations, unanticipated hazards as to which we have limited or no insurance coverage, failure of third party partners to fulfill their capital and other commitments, the ability to satisfy future cash obligations and environmental costs, adverse conditions, such as high temperatures and pressure that could lead to mechanical failures or increased costs, the ability to retain current or future lease acreage rights, the ability to satisfy future cash obligations and environmental costs, access to capital to fund drilling activities, as well as other general exploration and development risks and hazards, and other factors.

Investors are cautioned that many of the assumptions upon which our forward-looking statements are based are likely to change after our forward-looking statements are made, including for example the market prices of oil and natural gas, which we cannot control, and production volumes and costs, some aspects of which we may or may not be able to control. Further, we may make changes to our business plans that could or will affect our results. We caution investors that we do not intend to update our forward-looking statements more frequently than quarterly, notwithstanding any changes in our assumptions, changes in our business plans, our actual experience, or other changes, and we undertake no obligation to update any 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

We need significant amounts of cash to service our debt. If we are unable to generate sufficient cash to service our debt, our financial condition and results of operations could be negatively affected.

As of December 31, 2011 our outstanding debt totaled $553.6 million, including $187.4 million of our 4% senior notes due December 30, 2017, $300 million of our 11.875% Senior Notes due November 15, 2014 and $66.2 million of our 5¼% Senior Notes due October 6, 2012 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. Our ability to generate cash will be affected by general economic, financial, competitive, legislative, regulatory and other factors that are beyond our control. Future borrowings may not be available to us under our amended and restated credit facility or from the capital markets in amounts sufficient to pay our obligations as they mature or to fund other liquidity needs. In addition, disruptions in the credit and financial markets, such as those that occurred in late 2008, can constrain our access to capital and increase its cost. The inability to service, repay or refinance our indebtedness would have a negative impact on our financial condition and results of operations.

Agreements governing our indebtedness restrict our ability to incur additional debt and contain covenants and other restrictions that 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 financial condition and results of operations.

Our 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, our 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 current ratio test (current assets to current liabilities, subject to certain adjustments as of the end of the quarter). During periods in which crude oil and natural gas prices or other conditions reflect the adverse impact of cyclical market trends or other factors, we may not be able to comply with the applicable financial covenants, which could have a material adverse effect on our financial condition.

Volatile oil and gas prices could adversely affect our financial condition and results of operations.

Our success is largely dependent on oil and natural gas prices, which are extremely volatile. Any substantial or extended decline in the price of oil and gas will have a negative impact on our business operations and future revenues. Moreover, oil and gas prices depend on factors we cannot control, such as:

- supply and demand for oil and gas and expectations regarding supply and demand;
- weather;

- actions by OPEC and other major producing companies;
- political conditions in other oil-producing and gas-producing countries, including the possibility of insurgency, terrorism or war in such areas;
- the prices of foreign imports and the demand for and availability of alternate fuel sources;
- technological advances affecting energy exploration, production and consumption;
- general economic conditions in the United States and worldwide, including the value of the U.S. dollar relative to other major currencies; and
- governmental regulations.

With respect to our business, prices of oil and gas will affect:

- our revenues, cash flows, profitability and earnings;
- our ability to attract capital to finance our operations and the cost of such capital;
- the amount that we are allowed to borrow; and
- the value of our oil and gas properties and our oil and gas reserve volumes.

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

From time to time, declines in the market price for oil and natural gas coupled with certain other operational factors trigger impairment assessments that may ultimately result in impairment charges to reduce the carrying values of our properties. Additional write-downs of the capitalized costs of individual oil and natural gas properties may occur if information comes to our attention to warrant a downward adjustment to our estimated proved oil and gas reserves, to increase our estimates of development costs or to conclude that the results of exploratory drilling will be unproductive. 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 the value 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 revised estimate of the field's fair market value. We also record charges if proved reserves are not discovered at exploratory wells. Any impairment charges that we take will reduce our earnings and potentially our stockholders' equity. Once incurred, an impairment charge cannot be reversed at a later date even if we experience subsequent 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 gas extracted from shale formations and LNG, may reduce the price of natural gas, and could have an adverse effect on our financial condition and results of operations.

Recently, there has been an increase in the worldwide supply of unconventional gas, including gas extracted from shale formations utilizing advances in techniques for horizontal drilling and the fracturing of rock formations and LNG. While until recently production of gas from unconventional sources was a relatively small portion of current North American gas production, it has been increasing and is expected to continue to increase in the future. The global financial crisis also significantly impacted financial and commodity markets and has contributed to extreme volatility in oil and natural gas markets since that time, especially for natural gas prices. The amount of natural gas in storage increased as a result of this decreased demand, which contributed to the current oversupply of natural gas. Many economic forecasts predict an oversupplied natural gas market over the near-to-intermediate term, the effect of which, absent other factors, could result in a low natural gas price environment for the next several years and possibly beyond.

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 2011 is comprised of approximately 66 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 the volume and price of the natural gas we produce, which would likely have an adverse effect on our financial condition 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. Any failure of our partners to fulfill their obligations and commitments to us could have an adverse effect on our financial condition and results of operations.

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 third parties 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 enter into contractual commitments with third parties 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, 2011, we had $268.5 million of contractual commitments related to our planned oil and gas exploration and development activities, including $36.0 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, would have an adverse effect on our operating results and financial condition.

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.

Our losses from continuing operations were $6.6 million in 2011, $117.0 million in 2010 and $204.9 million in 2009. No assurance can be given that we will achieve profitability or positive cash flows from our operations in the future. Our failure to achieve profitability in the future could adversely affect the trading price of our securities and our ability to raise additional capital. In addition, while there are signs that the global economy has improved, the potential remains for further volatility and disruption in the capital and credit markets. During the recent global recession, the markets produced downward pressure on stock prices and credit capacity for certain issuers without regard to those issuers' underlying financial strength. If these levels of market disruption and volatility return, our business, financial condition and results of operations, as well as our ability to access capital, may all be negatively impacted.

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, 2011, we had accrued $326.4 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, 2011, we had $14.3 million relating to accrued reclamation liabilities with respect to our discontinued sulphur operations at Main Pass and $3.4 million relating to accrued reclamation liabilities with respect to our other discontinued sulphur operations. We have concluded our closure activities at the Port Sulphur facilities following damages sustained by the facilities from Hurricanes Katrina and Rita in 2005.

We cannot give assurance 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

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 and ultra-deep wells. Our drilling operations may be changed, delayed or canceled as a result of numerous factors that we cannot control, including:

- continued economic uncertainty 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 pressures 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 give assurance 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 or ultra-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. However, flow testing is required to confirm the ultimate hydrocarbon flow rates from the separate zones within this prospect. Completion activities of the Davy Jones No. 1 discovery well are in an advanced stage with completion and flow testing expected in the first quarter 2012. However, there is no assurance that the completion and testing activities will remain on schedule and that we will be able to effectively complete the flow testing of this prospect, or that once completed, our previously expressed views as to the potential 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 presents technical challenges.

The continuing 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 full development and 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.

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:

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

We incurred $509.5 million in capital expenditures in 2011. Depending on drilling results and follow on development opportunities, we expect 2012 capital expenditures to be approximate $500 million, including $300 million for exploration and $200 million for development. 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 raise 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 be adversely affected.

The high-rate production and depletion characteristics of our Gulf of Mexico properties subject us to high reserve replacement needs. If we are unable to replace the reserves that we have produced, our reserves and revenues will decline.

Our future success 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 with respect to 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.

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.

Investors 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, 2011. 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.

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 give assurance that our oil and gas operations will enable us to achieve or sustain positive earnings or cash flows from operations in the future.

In the event we are unable to procure or maintain the suspension of operations (SOO) granted by the BSEE 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 BOEM and BSEE and require compliance with BOEM and BSEE regulations and the 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 BSEE 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 BSEE 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 BSEE 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, 2011, approximately 11,000 of the 286,000 gross acres associated with our ultra-deep gas play are scheduled to expire in 2012.

While it is not uncommon for companies in our industry to continue to operate leases under an SOO granted by the BSEE, in the event (1) we fail to satisfy any obligations or conditions set forth in an SOO with respect to a particular lease, (2) we are unable to procure an SOO from the BSEE prior to the expiration of a primary lease term, (3) the BSEE denies a request to grant an additional SOO (or an extension of an existing SOO) with respect to a particular lease, or (4) the BSEE 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.

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 catastrophic explosion of the Deepwater Horizon in the Gulf of Mexico has resulted in increased governmental supervision of drilling, exploration and production activities in U.S. coastal waters, which could adversely affect our operations.

In April 2010, the *Deepwater Horizon*, an offshore drilling rig located in the deepwater of the Gulf of Mexico, sank following a catastrophic explosion and fire, which significantly and adversely disrupted oil & gas exploration activities in the Gulf of Mexico. The commission appointed by the President to study the causes of the catastrophe released its report and has recommended to the President certain legislative and regulatory measures that should be taken in order to minimize the possibility of a reoccurrence of a disastrous spill. In response to the *Deepwater Horizon* spill and the release of the commission report, the costs of conducting drilling and exploration activities in the Gulf of Mexico, particularly in deepwater, have increased.

Our operations are focused on the shelf of the Gulf of Mexico and Gulf Coast areas, where we maintain one of the largest acreage positions in the shallow waters of this region and have a significant number of ongoing exploration and development projects. In response to the catastrophe, the United States government imposed a suspension of all deepwater drilling and exploration activity in the Gulf of Mexico that expired on November 30, 2010. We do not operate in the deepwater of the Gulf of Mexico. However, although exploration activity in the shallow waters of the Gulf of Mexico has been allowed to re-commence, a de facto suspension has existed in that market, as new safety and permitting requirements have been imposed on shallow water operators, and only a limited number of new drilling permits have been issued to shallow water operators since the catastrophe.

There are a number of uncertainties affecting the oil and gas industry that continue to exist in the aftermath of the *Deepwater Horizon* events and the release of the commission report, including the possible increase or elimination of the current $75 million cap for non-reclamation liabilities under the Oil Pollution Act of 1990, the uncertainty as to the continued availability and affordability of insurance for drilling and exploration activities, the uncertain overall legislative and regulatory response to the catastrophe, and the continuing difficulty and delay in obtaining drilling permits in the shallow water on a timely basis. Although the eventual outcome of these developments is currently unknown, additional regulatory and operational costs could have an adverse effect on our financial condition and results of operations.

The oil and gas industry is highly competitive and we face strong competition.

The business of oil and natural gas exploration, development and production is very competitive. Competition is particularly intense for prospective undeveloped acreage and purchases of proved oil and gas reserves. There is also competition for the rigs and related equipment and services that are necessary for us to develop and operate our oil and natural gas properties. Our competitive position is also highly dependent on our ability to recruit and retain geological, geophysical and engineering expertise. We are likely to continue to experience increased costs to attract and retain such professionals. We compete for prospects, proved reserves, field services and qualified oil and gas professionals with major integrated oil and gas companies and numerous independent oil and gas companies, individual producers and operators. Many of our competitors have significantly greater financial and other resources than we have and may be better positioned to:

- access capital at a lower cost;
- adapt to fluctuations in the credit markets and periods of distressed or adverse economic conditions;
- adapt to an increasingly burdensome regulatory environment, particularly with respect to bearing increased compliance costs, in response to the *Deepwater Horizon* or other catastrophic events and uncertainties;
- define, evaluate, bid for and purchase properties and prospects;
- obtain equipment, supplies and labor on favorable terms;
- develop, or buy, and implement new technologies; and
- access more information relating to prospects.

We cannot control the activities related to properties in which we have an interest but do not operate.

Other companies operate several of the properties in which we have an interest. We do not control, and only have a very limited ability to influence, 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.

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, control of well, business interruption (when economically feasible), 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 and control of well 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 and control of well 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 windstorm 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.

Hedging our production may expose us to various risks.

While we do not currently engage in hedging activities, in the future 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 delayed or less than expected;
- the counterparty to the hedging contract is unable to satisfy its obligations; or
- there is an adverse change in the expected differential between the underlying price in the hedging agreement and actual prices received for our production.

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. The level of derivative activity depends on our view of market conditions, available derivative prices and our operating strategy.

We may not be able to obtain the necessary financing to complete the development of the Main Pass Energy Hub™ (MPEH™) project, 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. Mine Safety Disclosures

Not applicable.

Executive Officers of the Registrant

Listed below are the names and ages, as of February 15, 2012, 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	73	Co-Chairman of the Board, President and Chief Executive Officer
Richard C. Adkerson	65	Co-Chairman of the Board
Nancy D. Parmelee	60	Senior Vice President, Chief Financial Officer and Secretary
Kathleen L. Quirk	48	Senior Vice President and Treasurer

James R. Moffett has served as our Co-Chairman of the Board since November 1998 and our President and Chief Executive Officer since May 2010. 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.

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.

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." The following table sets forth, for the period indicated, the range of high and low sales prices, as reported by the NYSE.

	2011		2010	
	High	Low	High	Low
First Quarter	$18.68	$14.94	$18.80	$ 8.18
Second Quarter	19.26	15.03	17.10	8.63
Third Quarter	18.83	9.75	18.04	9.91
Fourth Quarter	16.57	8.25	19.80	14.18

As of February 15, 2012 there were 6,793 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 has the sole discretion as to the timing and amount of any cash dividends.

Issuer Purchases of Equity Securities

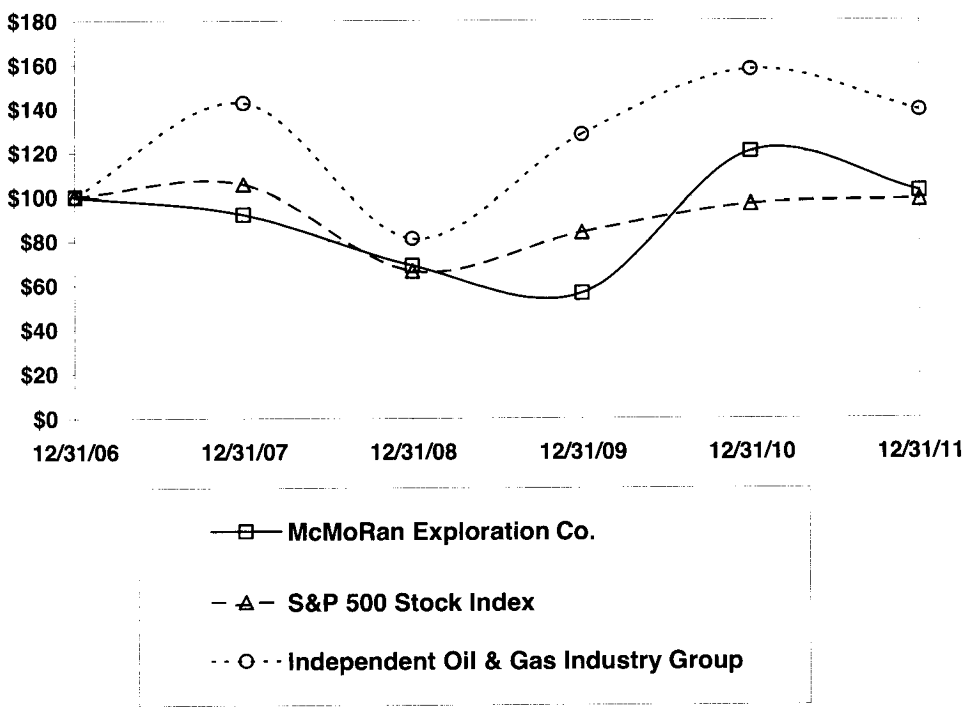
In 1999, our Board of Directors approved an open market share purchase program for up to 2.0 million shares of our common stock. In 2000, the Board of Directors authorized the purchase of up to an additional 0.5 million shares under the program. The program does not have an expiration date. No shares were purchased during the three years ending December 31, 2011. 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 2007 through 2011. This comparison assumes $100 invested on December 31, 2006 in (1) our common stock, (2) an Independent Oil & Gas Industry Group, and (3) 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,					
	2006	2007	2008	2009	2010	2011
McMoRan Exploration Co.	$100.00	$92.05	$68.92	$56.40	$120.53	$102.32
S&P 500 Stock Index	100.00	105.49	66.46	84.05	96.71	98.75
Independent Oil & Gas Industry Group	100.00	142.63	81.15	128.25	157.83	139.21

* Total Return Assumes Reinvestment of Dividends

Unregistered Sales of Equity Securities

On February 9, 2011, we privately negotiated the induced conversion of approximately 8,100 shares of our 8% preferred stock with a liquidation preference of $8.1 million into approximately 1.2 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 conversion of these shares of 8% preferred stock, we paid an aggregate of $1.5 million in cash to the holder of these shares, which amount was included as a charge in our 2011 consolidated statements of operations within preferred dividends, amortization of convertible preferred stock issuance costs and inducement payments for early conversion of preferred stock. Following this transaction, approximately 14,000 shares of our 8% preferred stock remain outstanding. This induced conversion was exempt from registration by virtue of the exemption provided under Section 3(a)(9) of the Securities Act.

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, 2011. 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.

Financial Data	2011	2010	2009	2008	2007
	(Financial data in thousands, except per share amounts)				
Years Ended December 31:					
Revenues [a]	$ 555,414	$ 434,376	$ 435,435	$ 1,072,482	$ 481,167
Depreciation and amortization [b]	307,902	282,062	313,980	854,798	256,007
Exploration expenses	81,742	42,608	94,281	79,116	58,954
Main Pass Energy Hub costs [c]	588	1,011	1,615	6,047	9,754
Insurance recoveries [d]	(91,076)	(38,944)	(24,592)	(3,391)	(2,338)
Operating income (loss)	1,368	(78,985)	(168,434)	(155,234)	3,509
Interest expense, net	(8,782)	(38,216)	(42,943)	(50,890)	(66,366)
Loss from continuing operations	(6,604)	(116,976)	(204,889)	(211,198)	(63,561)
Income (loss) from discontinued operations	(9,364)	(3,366)	(6,097)	(5,496)	3,827
Net loss applicable to common stock	(58,768)	(197,443)	(225,318)	(238,980)	(63,906)
Basic and diluted net income (loss) per share of common stock:					
Continuing operations	$ (0.31)	$ (2.04)	$ (2.79)	$ (3.79)	$ (1.97)
Discontinued operations	(0.06)	(0.04)	(0.08)	(0.09)	0.11
Basic and diluted net loss per share	$ (0.37)	$ (2.08)	$ (2.87)	$ (3.88)	$ (1.86)
Average basic and diluted common shares outstanding [e]	159,216	95,125	78,625	61,581	34,283
At December 31:					
Working capital (deficit)	$ 265,508	$ 628,597	$ 148,357	$ 3,601	$ (221,302)
Property, plant and equipment, net	2,181,926	1,785,607 [f]	796,223	992,563	1,503,359
Total assets	2,939,214	2,899,364	1,248,882	1,330,282	1,715,288
Oil and gas reclamation obligations	326,394	358,624	428,711	421,201	294,737
Long-term debt, including current portion	553,586	559,976 [e]	374,720	374,720	689,000
Stockholders' equity	1,722,964	1,724,337 [e,f]	265,808	309,023	372,229

a. Includes service revenues totaling $13.1 million in 2011, $15.6 million in 2010, $12.5 million in 2009, $13.7 million in 2008 and $5.9 million in 2007 (Note 1).
b. Includes impairment charges of $71.1 million in 2011, $107.2 million in 2010, $75.3 million in 2009, $332.6 million in 2008 and $13.6 million in 2007 (Note 4).
c. Reflects costs associated with pursuit of the licensing, design and financing plans related to the potential establishment of an alternate use energy hub at Main Pass Block 299 in the Gulf of Mexico (Note 16).
d. Reflects proceeds received in connection with our oil and gas property hurricane-related insurance claims (Note 4).
e. Reflects the applicable impact of common and preferred stock and convertible debt transactions during the periods from 2007 through 2011 (Notes 2, 6, 8 and 9).
f. Includes the impact of the approximate $1 billion acquisition of Gulf of Mexico shallow water properties from Plains Exploration & Production Company (PXP Acquisition), including the issuance of 51 million shares of McMoRan common stock (Note 2).

	2011	2010	2009	2008	2007
Operating Data					
Years Ended December 31:					
Sales Volumes:					
Gas (thousand cubic feet, or Mcf)	45,000,000	38,019,100	50,081,900	59,886,900	38,994,000
Oil (barrels)	2,716,900	2,480,900	2,994,100	3,635,200	2,380,500
Natural gas liquids (NGLs, Mcf equivalent)	6,925,400	5,956,700	5,759,600	8,004,400	2,153,300
Average realization:					
Gas (per Mcf)	$ 4.32	$ 4.77	$ 4.22	$ 9.96	$ 7.01
Oil (per barrel)	104.45	77.93	60.22	104.00	76.55
NGLs (per Mcf equivalent)	9.13	7.32	5.43	10.40	8.95
All hydrocarbon products (per Mcf equivalent)	7.93	7.11	5.73	11.79	8.57

Items 7. and 7A. Management's Discussion and Analysis of Financial Condition and Results of Operations 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 in the shallow waters (less than 500 feet of water) of the Gulf of Mexico and onshore in the Gulf Coast area of the United States. Our exploration strategy is focused on targeting large structures on the "deep gas play," and on the "ultra-deep play." Deep gas prospects target large deposits at depths typically between 15,000 and 25,000 feet. Ultra-deep prospects target objectives at depths typically below 25,000 feet. 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. We have rights to approximately 886,000 gross acres, including approximately 286,000 gross acres associated with the ultra-deep gas play below the salt weld. Our focused strategy enables us to efficiently use our geological, engineering and operational expertise in these areas where we have more than 40 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.

Our technical and operational expertise is primarily in the Gulf of Mexico and onshore in the Gulf Coast area. We leverage our expertise by attempting to identify exploration opportunities with high potential. 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 there is substantial infrastructure in our focus area to support the production and delivery of product. 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.

On December 30, 2010, we completed the acquisition of Plains Exploration & Production Company's (PXP) shallow water Gulf of Mexico shelf assets (PXP Acquisition). Under the terms of the transaction, we issued 51 million shares of our common stock and paid $75.0 million cash to PXP, with total consideration for the transaction of approximately $1 billion based on the value of our common stock on the closing date. In addition, the purchase price included $45.5 million associated with estimated revenues, expenses and capital expenditures attributable to the properties from the August 1, 2010 effective date through the December 30, 2010 closing date, and the assumption of approximately $8.8 million of related asset retirement obligations. The substantial majority of properties acquired from PXP represented their interests in certain deep gas and ultra-deep exploration projects that, prior to the transaction, were jointly owned by us and PXP. The acquisition purchase price was allocated to the properties acquired with approximately 19% allocated to proved properties and the remaining portion allocated to unevaluated oil and gas properties. We incurred approximately $9.4 million in transaction related costs for this transaction. Concurrent with the PXP Acquisition, we issued $700 million of 5.75% Convertible Perpetual Preferred Stock (5.75% preferred stock) and $200 million of 4% Convertible Senior Notes (4% senior notes) to certain investors (Notes 2, 6 and 8).

The transaction increased our scale of operations on the Gulf of Mexico shelf, consolidated our ownership in core focus areas, expanded our participation in future production from our deep gas and ultra-deep exploration and development programs and increased current reserves and production. In addition, we expect to continue to benefit from our positive relationship with PXP through PXP's significant shareholding position in our company. Our total drilling costs for our nine in-progress or unproven wells totaled $1,396.4 million, including $700.3 million in allocated purchase costs associated with property acquisitions. For additional information regarding our investment in in-progress or unproven wells see Items 1. and 2. "Business and Properties" included in this Form 10-K.

During the year ended December 31, 2011, we funded $150.0 million of net abandonment expenditures. We recorded approximately $91.1 million of insurance gains during 2011, representing reimbursements for portions of our previously incurred hurricane damage repair and property abandonment costs. We plan to spend approximately $60 million in 2012 for the abandonment and removal of oil and gas structures in the Gulf of Mexico.

During the year ended December 31, 2011, we invested $509.5 million on capital-related projects primarily associated with our exploration activities. We expect 2012 capital expenditures to approximate $500 million, including $300 million for exploration and $200 million for development. Capital spending is subject to change, depending on drilling results, follow-on development activities, and general market factors and will be funded based on our available cash and cash flows, including potential participation by new partners in exploration and development projects.

We continue to monitor the global financial and credit markets, as well as the fluctuations in oil and natural gas market prices, all of which may ultimately have a material effect 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.

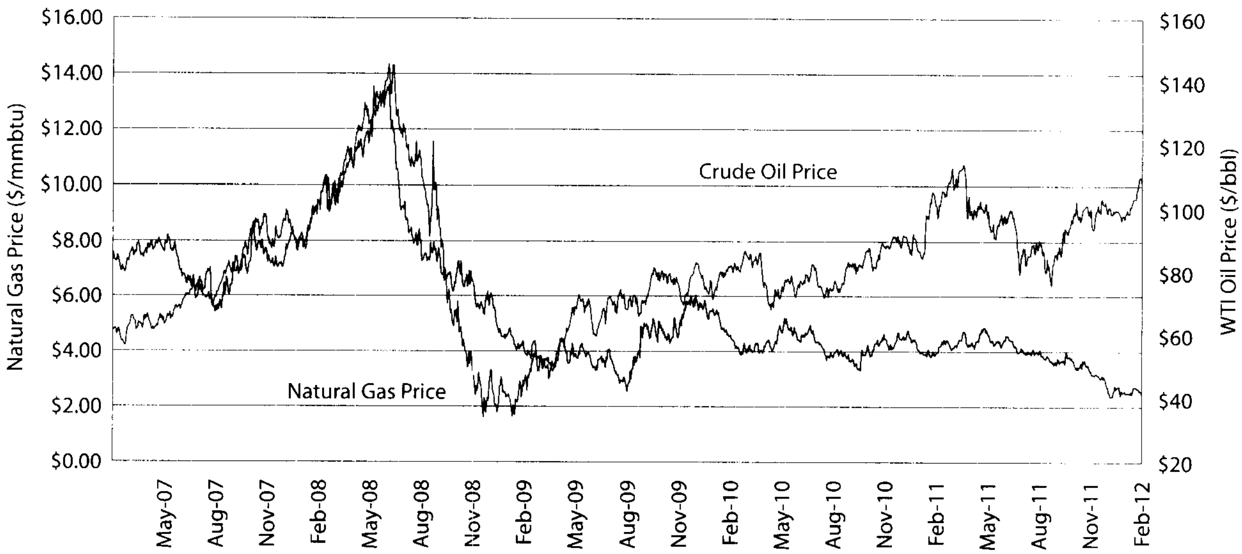
North American Natural Gas and Oil Market Environment

Our 2011 production volume was comprised of approximately 66 percent natural gas and 34 percent oil and natural gas liquids, while our revenues were derived 64 percent from oil and natural gas liquids and 36 percent from natural gas. North American natural gas averaged $4.03 per MMbtu during 2011. The spot price for natural gas was $2.45 per MMbtu on February 27, 2012. The average oil price for 2011 was $95.11 per barrel and the spot price for oil was $108.56 per barrel on February 27, 2012. Future oil and natural gas prices are subject to change and these changes are not within our control.

Currently, natural gas supply is higher than related demand. One factor contributing to decreased demand was the global financial crisis that began in late 2007/early 2008. The global financial crisis also significantly impacted financial and commodity markets and has contributed to extreme volatility in oil and natural gas markets since that time, especially for natural gas prices. The amount of natural gas in storage increased as a result of this decreased demand, which contributed to the current oversupply of natural gas. In addition, new sources for natural gas, such as shale gas, are contributing to the current oversupply of natural gas. Many economic forecasts predict an oversupplied natural gas market over the near-to-intermediate term. While the spot price of natural gas remained above $4.00 per MMbtu for several months in 2011, later in the year prices began to decline significantly, and in early 2012 the spot price for natural gas fell below $2.50 per MMbtu; as of February 27, 2012 the spot price for natural gas was $2.45 per MMbtu due in part to an unseasonably mild winter. Prolonged weak natural gas market conditions would likely have a negative impact on our results of operations and financial condition and may require us to reduce planned capital spending and adjust aspects of our current business strategy.

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 - February 2007 - February 2012



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

Production Update

Fourth-quarter 2011 production averaged 170 MMcfe/d net to us, compared with 144 MMcfe/d in the fourth quarter of 2010. Production in the fourth quarter of 2011 was in line with our previously reported estimates in October 2011. Annual production in 2011 averaged 187 MMcfe/d, compared with 161 MMcfe/d in 2010. Excluding production from Davy Jones, which will be incorporated following the pending flow test, production is expected to average approximately 130 MMcfe/d for the year 2012, including 155 MMcfe/d in the first quarter of 2012. We expect to increase 2012 production estimates if the Davy Jones flow test is successful. Our estimated production rates are dependent on the timing of planned recompletions, production performance, weather and other factors.

Production from the Flatrock field averaged a gross rate of approximately 147 MMcfe/d (60 MMcfe/d net to us) in the fourth quarter of 2011, compared with 165 MMcfe/d (31 MMcfe/d net to us) in the fourth quarter of 2010. Production from Flatrock is expected to be lower in 2012 compared to 2011 as a result of depletion of the resource in the currently producing zones. Following depletion of currently producing zones, we are planning several recompletions to additional pay zones which are expected to increase production in future years. Cumulative gross production from Flatrock through December 31, 2011 totaled 257 Bcfe and independent reservoir engineers' estimates of remaining reserves at December 31, 2011 totaled 197 Bcfe (8/8ths), 81.1 Bcfe net to us. We own a 55.0 percent working interest and a 41.3 percent net revenue interest in the Flatrock field.

Effects of 2010 *Deepwater Horizon* Incident on Drilling and Other Commitments

We have significant drilling and other commitments associated with our business strategy. The April 2010 *Deepwater Horizon* incident and the industry-wide increase in regulatory and compliance related issues resulting therefrom have created additional uncertainties, some of which have delayed drilling schedules and presented challenges in managing ongoing rig commitments. As a result, beginning in the second quarter of 2011 we managed costs incurred relating to an idle drilling rig by negotiating an arrangement with a third party to use the rig on a short-term basis through the third quarter extending into early October 2011. Net idle drilling rig costs in excess of the third party reimbursements recorded to exploration expense for the year ended December 31, 2011 totaled approximately $7.0 million.

Acreage Position

For information regarding our acreage position, see "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 income during 2011 totaled $1.4 million which reflects (a) $71.1 million in impairment charges to reduce net carrying values of certain of our oil and gas properties to fair value primarily due to well performance issues and other operational factors that had a negative impact on reserve recoverability and the impact of increased capitalized costs from asset retirement obligation adjustments; (b) adjustments totaling approximately $57.3 million charged against earnings for asset retirement obligations associated with certain of our oil and gas properties, approximately $19.8 million of which was covered for reimbursement under our insurance program; (c) $54.0 million in workover expenses; (d) a gain of $91.1 million for net insurance recoveries associated with insured hurricane-related losses; (e) $18.3 million in charges related to stock-based compensation expense; and (f) $42.3 million in charges to exploration expense for unproductive well costs and certain unproven leasehold cost reductions.

Our operating loss during 2010 totaled $79.0 million which reflects (a) $107.2 million in impairment charges to reduce net carrying values of certain of our oil and gas properties to fair value primarily related to the declines in market prices for oil and natural gas during 2010 and other operational factors that had a negative impact on reserve recoverability; (b) $9.0 million of transaction costs charged to general and administrative expense related to the PXP Acquisition; and (c) $14.5 million of non-productive exploratory drilling and related costs. These costs were offset by $38.9 million of insurance recoveries (gains) recognized as partial reimbursements for insured losses related to the September 2008 hurricanes in the Gulf of Mexico, a $4.2 million gain on oil and gas derivative contracts, and a $3.5 million gain on sale of an oil and gas property.

Our operating loss during 2009 totaled $168.4 million which reflects (a) $75.3 million in impairment charges to reduce net carrying values of certain of our oil and gas properties to fair value primarily related to the declines in market prices for oil and natural gas during 2009 and 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) a $17.4 million gain on 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):

	2011	2010
Oil and natural gas revenues - prior year period	$ 418,816	$ 422,976
Increase (decrease)		
Price realizations:		
Natural gas	(20,250)	20,911
Oil and condensate	72,052	43,937
Sales volumes:		
Natural gas	33,299	(50,905)
Oil and condensate	18,391	(30,905)
NGL revenue	19,629	12,325
Other	373	477
Oil and natural gas revenues - current year period	$ 542,310	$ 418,816

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 five years in the period ended December 31, 2011.

Our oil and natural gas sales volumes totaled 68.2 Bcfe in 2011, 58.9 Bcfe in 2010 and 73.8 Bcfe in 2009. The increase in volumes from 2010 to 2011 was primarily related to additional volumes from producing properties acquired during the PXP Acquisition as well as additional volumes from our Laphroaig No. 2 well that commenced production during the second quarter 2011. These volume increases were partially offset by production declines from several maturing properties. The decrease in volumes between the 2009 and 2010 period primarily relates to anticipated declines in production associated with maturing properties acquired in the 2007 property acquisition as well as timing delays for certain well recompletion and development activities in 2010. Average realizations received for oil sold during 2011 increased by 34 percent over amounts received in 2010, which increased by 29 percent compared to amounts received in 2009. Average realizations for natural gas sold during 2011 decreased 9 percent from amounts received in 2010, which increased 13 percent from amounts received during 2009. The variations in realizations for natural gas and oil sold during these years are related to the volatility in commodity prices during 2011, 2010 and 2009.

Our 2011 revenues included $63.2 million of natural gas liquids (NGLs) sales associated with approximately 6.9 Bcf equivalents for products (ethane, propane, butane, etc.) recovered from the processing of our natural gas. This increase was primarily due to our increased ownership in the Flatrock property as a result of the PXP Acquisition that occurred in late 2010, and an approximate 25% increase in NGL sales price realizations. The amounts of NGL sales totaled $43.6 million from 6.0 Bcf equivalents during 2010 and $31.3 million from 5.8 Bcf equivalents during 2009. This variation is primarily due to an approximate 35% increase in NGL sales price realizations from 2009 to 2010.

Our service revenues totaled $13.1 million in 2011, $15.6 million in 2010 and $12.5 million in 2009. The decrease in 2011 was due to a reduction in certain overhead fees allocated to partners related to our operations.

Production and delivery costs. The following table reflects our production and delivery costs for the years ended December 31, 2011, 2010 and 2009 (in millions, except per Mcfe amounts):

	2011	Per Mcfe	2010	Per Mcfe	2009	Per Mcfe
Lease operating expense	$113.0	$1.66	$105.4	$1.79	$115.9	$1.57
Workover costs	54.0	0.79	22.9	0.39	18.0	0.25
Hurricane related repairs	-	-	6.9	0.12	14.1	0.19
Insurance	14.3	0.21	26.5	0.45	23.9	0.32
Transportation, production taxes and other	25.0	0.36	21.1	0.36	21.1	0.29
Total production and delivery costs	$206.3	$3.02	$182.8	$3.11	$193.0	$2.62

Lease operating expense in 2011 increased by approximately $7.6 million compared to 2010, primarily reflecting the impact of the operations of the assets acquired in the PXP Acquisition ($12.5 million of LOE on 18.1 Bcfe of production in the year ended December 31, 2011). The properties acquired in the PXP Acquisition generated approximately 27% of our total production volumes in the year ending December 31, 2011.

Workover costs increased by approximately $31.1 million in the year ended December 31, 2011 compared to 2010. The increase was primarily due to an unsuccessful workover at our Vermillion 16 property totaling approximately $17.5 million and also included $15.6 million of costs associated with certain repairs and other workover costs incurred at our Main Pass 299 facility during 2011.

Hurricane-related repairs decreased by approximately $6.9 million in the year ended December 31, 2011 compared to the year ended 2010 as the repair work related to the 2008 hurricane events was completed in 2010.

Transportation, production taxes and other increased by approximately $3.9 million compared to 2010 primarily due to the additional assets and interests acquired in the PXP Acquisition.

Lease operating expense in 2010 decreased by approximately $10.5 million compared to 2009, primarily reflecting the impact of decreased production volumes partially offset by higher per unit costs resulting from the effect of certain fixed costs spread over lower production volumes. Hurricane-related repairs decreased by approximately $7.2 million in 2010 compared to 2009 as the repair work related to the 2008 hurricane events neared completion.

Market insurance premium rates for operators in the Gulf of Mexico have increased significantly in recent years following hurricane events and the 2010 *Deepwater Horizon* incident. In addition, coverage for certain types of catastrophic events, such as hurricanes, has become significantly more restrictive. Because of this and in consideration of our on-going efforts to mitigate our exposure to the costs of storm-related structural damage through our aggressive reclamation program to remove platforms and related structures for non-productive wells, we did not obtain coverage for windstorm perils in the mid-year renewal of our annual insurance program. We maintained coverage for well control up to $150 million for all conventional wells and up to $250 million for ultra-deep wells. Both the limits of coverage and deductibles under this policy are scaled to our working interest in the covered location. The elimination of windstorm coverage resulted in a significant reduction to our insurance costs in 2011 compared to 2010. We also renewed our Oil Spill Financial Responsibility policy coverage which has a $105 million limit for our Main Pass 299 oil production operations and a $35 million limit for our other producing operations. For additional information related to risks associated with our insurance coverage, see Part I, Item 1A. "Risk Factors" included in this annual report on Form 10-K for the year ended December 31, 2011.

Depletion, depreciation and amortization expense. The following table reflects the components of our depletion, depreciation and amortization expense for the years ended December 31, 2011, 2010 and 2009 (in millions, except per Mcfe amounts):

	2011	Per Mcfe	2010	Per Mcfe	2009	Per Mcfe
Depletion and depreciation expense	$165.3	$2.42	$148.4	$2.52	$205.5	$2.78
Accretion expense	71.5	1.05	26.5	0.45	33.2	0.45
Impairment charges/losses	71.1	1.04	107.2	1.82	75.3	1.02
Total depletion, depreciation and amortization expense	$307.9	$4.51	$282.1	$4.79	$314.0	$4.25

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 revisions over time as changes in reserve estimates and fluctuations in the recorded amounts of property, plant and equipment and asset retirement obligations occur. The increase in depletion and depreciation expense in the year ended December 31, 2011 compared to the 2010 period is primarily related to higher sales volumes in 2011 offset by the reduction in the carrying value of our proved oil and gas property costs resulting from property impairments. Reductions in the amounts of our depletion and depreciation expense in 2010 primarily reflect lower production rates as well as the significant reduction in the carrying value of our proved oil and gas property costs resulting from property impairments.

Since 2007 and through 2011 we have funded over $360 million of reclamation costs to settle a significant portion of the asset retirement obligations assumed in an oil and gas property acquisition in 2007, including certain properties damaged in the 2008 hurricanes. Of this amount, approximately $277 million has been incurred during the last two years as a result of our efforts to reduce our exposure to future weather-related events and to remove idle structures in accordance with regulatory requirements. We intend to spend approximately $60 million on additional reclamation activities in 2012 to settle the asset retirement obligations of certain of our maturing properties. Our estimates of existing asset retirement obligations involve inherent uncertainties and are subject to change over time as a result of several factors, including, without limitation, changes in the industry's regulatory environment, changes in the cost and availability of required equipment and expertise to complete the work, and changes in timing, and scope that are identified as reclamation projects progress. We revise our reclamation estimates, as appropriate, when such changes in estimates become known.

The results from these reclamation activities as well as information obtained from other industry sources indicate that the cost to conduct reclamation projects in the offshore Gulf of Mexico region has increased, particularly since the occurrence of the 2010 *Deepwater Horizon* incident. As a result, we re-assessed the estimates of substantially all of our oil and gas property asset retirement obligations in 2011. As a result of this re-assessment, we revised our estimates related to certain recently completed, ongoing and/or near-term reclamation projects resulting in an increase to accretion expense of approximately $57.3 million. Approximately $19.8 million of these charges were reimbursed to us under our insurance policies related to damage restoration costs resulting from the 2008 hurricane events. In addition, we also revised our estimates related to certain longer term producing properties resulting in adjustments that increased property, plant and equipment by approximately $54.6 million.

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. We recorded impairment charges during the year ended December 31, 2011 of $71.1 million primarily due to well performance issues, the decline in market prices for natural gas, and the impact of increased capitalized costs for certain properties from asset retirement obligation adjustments. 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 $107.2 million in 2010 and $75.3 million in 2009.

As more fully identified in Item 1A. "Risk Factors" and elsewhere in this Form 10-K, a combination of any or all of the conditions described above, including the factors that contributed to the recognition of significant impairment charges in 2011, 2010 and 2009, 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,		
	2011	2010	2009
Geological and geophysical, including 3-D seismic purchases [a]	$ 22.4	$ 19.3	$ 26.8
Dry hole costs	42.3 [b]	14.5 [c]	61.5 [d]
Other [e]	17.0	8.8	6.0
	$ 81.7	$ 42.6	$ 94.3

a. Includes compensation costs associated with stock-based awards totaling $8.3 million in 2011, $8.6 million in 2010 and $6.6 million in 2009.
b. Includes nonproductive exploratory drilling and related costs of $37.8 million associated with the Blueberry Hill #9 STK1 well and $2.5 million associated with the Platte well determined to be non-commercial in January 2011. Also includes unproven leasehold cost reductions of $2.2 million.
c. Includes $7.2 million of nonproductive exploratory drilling and related costs primarily associated with the Blueberry Hill offset appraisal well incurred below 19,000 feet which was determined to be non-commercial, net of other miscellaneous dry hole adjustments. Also includes $7.3 million of nonproductive exploratory drilling costs incurred through December 31, 2010 related to the Platte well.
d. 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).
e. Includes $7.0 million in idle drilling rig charges in the year ended December 31, 2011. Includes $4.2 million, $6.0 million and $3.2 million in drilling related insurance costs for the years ended December 31, 2011, 2010 and 2009, respectively.

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). Under this arrangement Moncrief and related entities have participated in several of our ultra-deep exploration projects including Davy Jones, Blackbeard East, Lafitte and Blackbeard West No. 2.

Also in 2009, we entered into an arrangement with Whitney Exploration LLC (Whitney) allowing Whitney to participate in certain of our ongoing exploration and development activities. In September 2011, we purchased Whitney's interests in the Davy Jones and Blackbeard East exploration projects for $10 million in cash, 2.8 million shares of our common stock and certain other non-cash consideration for a total purchase price of approximately $49.1 million.

Other Financial Results

Operating

Our general and administrative expenses totaled $49.5 million in 2011, $51.5 million in 2010 and $43.0 million in 2009. The decrease in these costs in 2011 from 2010 is primarily related to a $6.9 million decrease in transaction costs and other professional service fees primarily associated with the PXP Acquisition during 2010, offset by $2.3 million in higher franchise taxes resulting from our increased stockholders' equity position related to the equity issued in the PXP Acquisition, $1.1 million in higher incentive compensation costs during 2011, $0.9 million in higher legal costs (largely related to the settlement of a litigation contingency matter) and approximately $0.3 million of higher information technology related costs for certain system enhancement activities. General and administrative expense for 2010 includes $9.0 million of transaction costs associated with the PXP Acquisition, primarily contributing to the $8.5 million increase in general and administrative expenses between the 2010 and 2009 periods.

In 2010 and 2009, we recorded aggregate gains of $4.2 million and $17.4 million, 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 impacted Gulf of Mexico operations in September 2008. Although there was no significant damage to our properties resulting from Hurricane Gustav, 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 approximately $200 million related to incurred repair costs, property impairments and additional estimated reclamation costs associated with the damaged properties. In December 2011, we reached a settlement with our insurers to finalize all outstanding claims from the 2008 hurricane events. We recognized net insurance recoveries of $91.1 million in 2011, $38.9 million in 2010 and $24.6 million in 2009.

We recorded $0.9 million and $3.5 million of gains on the sale of oil and gas properties in 2011 and 2010, respectively. There were no such transactions in 2009.

Non-Operating

Interest expense, net of capitalized interest, totaled $8.8 million in 2011, $38.2 million in 2010 and $42.9 million in 2009. We capitalized interest totaling $47.4 million in 2011, $10.1 million in 2010 and $3.9 million in 2009. Capitalized interest increased over the past three years as a result of our increased investment in significant exploration and development projects, especially following the PXP Acquisition.

Other income totaled $0.8 million in 2011, $0.2 million in 2010 and $4.0 million in 2009. Interest income totaled $0.8 million in 2011, $0.2 million in 2010 and $0.7 million in 2009. 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.

We recorded no income tax benefit (expense) in 2011 and 2010. Income tax benefit totaled $2.4 million in 2009. Our $2.4 million income tax benefit in 2009 primarily related to the carry back of our 2009 tax net operating loss (NOL) and refund of our 2008 federal alternative minimum tax.

In February 2012, the Obama Administration released its Fiscal Year 2013 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 losses of $9.4 million in 2011, $3.4 million in 2010 and $6.1 million in 2009. Our discontinued operations' results are summarized in Note 10.

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. Cumulative legal fees and related settlement amounts incurred with respect to this indemnification total approximately $1.1 million (since 2002). In addition, we substantially completed the closure project for our former terminal facilities at Port Sulphur, in 2011.

CAPITAL RESOURCES AND LIQUIDITY

Our primary sources of liquidity are net cash provided from operations, cash from financings, and available drawings under our credit facility. Our cash flow from operations is subject to changes in oil and natural gas prices, which can be volatile and over which we have no control. Significant declines in commodity prices may negatively impact our revenue, earnings and cash flow, with a corresponding effect on capital spending and potentially our liquidity. Sales volumes, collections and costs may also impact our cash flow. On December 31, 2011, our cash balance totaled $568.8 million and cash flow from operations increased by approximately $128.8 million in 2011 from 2010. We also have a $150 million credit facility, of which $100 million is used to support a reclamation surety letter of credit, resulting in $50 million of currently available borrowing capacity.

Generating sufficient levels of long-term operating cash flow is dependent on our ability to replace reserves produced and control our ongoing operational costs. Our ability to maintain and grow our production and cash flow is significantly dependent on our success in funding, finding and developing oil and gas reserves through successful drilling programs and property acquisitions. These activities require substantial capital investment.

Our primary uses of cash are exploration, development and acquisitions of properties to replace depleted reserves, payment of ongoing operational costs, including the costs to abandon and reclaim depleted properties, and repayment of principal and interest on outstanding debt. We expect 2012 capital expenditures to approximate $500 million, including $300 million for exploration and $200 million for development. In addition, we plan to spend approximately $60 million to abandon and remove structures from depleted properties in 2012. We plan to fund our capital and other spending through available cash, cash flow from operations and participation by partners in exploration and development projects.

Although we do not budget for acquisitions, we continually evaluate acquisition opportunities. The timing and size of acquisitions are unpredictable and future acquisition opportunities could fully utilize or even exceed our existing capital resources. If acquisition opportunities are presented to us, we would consider various funding sources to provide capital, as we have in the past.

Our capital spending will continue to be driven by opportunities, drilling results and follow-on development activities 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 results 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.

The table below summarizes our historical 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).

	Years Ended December 31,		
	2011	2010	2009
Continuing operations			
Operating [a]	$ 242.0	$ 100.4	$ 136.9
Investing	(518.1)	(300.5)	(138.0)
Financing	(45.9)	866.5	154.8
Discontinued operations			
Operating	$ (15.0)	$ (2.2)	$ (5.7)
Investing	-	-	-
Financing	-	-	-
Total cash flow			
Operating	$ 227.0	$ 98.2	$ 131.2
Investing	(518.1)	(300.5)	(138.0)
Financing	(45.9)	866.5	154.8

a. Net of reclamation spending of $150.0 million, $115.1 million and $45.9 million in 2011, 2010 and 2009, respectively. As of December 31, 2011, we have approximately $326.4 million recorded for estimates of remaining oil and gas property asset retirement obligations.

Comparison of Year-To-Year Cash Flow

Operating Cash Flow

Operating cash flow increased $128.8 million in 2011 from 2010 primarily a result of $121.0 million of higher revenue and $52.1 million in additional insurance recoveries, partially offset by approximately $23.5 million of higher production and delivery costs and $34.9 million in additional reclamation expenditures.

Although our revenues from oil and natural gas remained relatively constant in 2010 compared to 2009, our operating cash flow decreased $32.9 million in 2010 compared to 2009 primarily resulting from $69.2 million of higher reclamation expenditures and $35.0 million of lower realized derivative gains, the effects of which were partially offset by $10.2 million of lower production and delivery charges, $4.7 million of lower geological, geophysical and other costs, $14.4 million of higher insurance recoveries, $3.1 million of increased service revenue and $40.9 million of positive working capital fluctuations between comparable years. In addition, $27.4 million of the working capital fluctuation was due to the use of inventory in our 2010 drilling operations that was purchased in prior periods, with the remaining portion of the positive variance primarily due to the effect of increased drilling activities on net payables and receivables in 2010.

Cash used in our discontinued operations in 2011, 2010 and 2009 primarily reflect caretaking, remediation and other closure costs associated with our Port Sulphur, Louisiana former sulphur terminal, which was substantially completed in 2011 (Note 10).

Investing Cash Flow

Our 2011 investing cash flow reflects exploration, development and other capital expenditures of $509.5 million and $9.5 million of property acquisition costs. Total cash used in investing activities increased approximately $217.6 million in 2011 compared to 2010 primarily due to our increased drilling activities and higher working interests in exploration and development projects resulting from the PXP Acquisition.

Our 2010 investing cash flow reflects capital expenditures of $217.3 million and $86.1 million of property acquisition costs. Total cash used in investing activities increased approximately $162.5 million in 2010 compared to 2009 primarily as a result of our increased investments in ultra-deep exploratory drilling and due to the cash portion of the consideration paid in the PXP Acquisition.

Financing Cash Flow

Our 2011 financing cash flow includes payments of dividends of \$36.5 million and conversion inducement payments of \$1.5 million. During the year ended December 31, 2011, in a privately negotiated transaction we agreed to induce the conversion of approximately 8,100 shares of our 8% preferred stock into approximately 1.2 million shares of our common stock for a payment of \$1.5 million. Following this inducement conversion transaction we have approximately 14,000 shares of our 8% preferred stock outstanding as of December 31, 2011. In addition, during the year ended December 31, 2011 we completed an offer to exchange up to \$74.7 million aggregate principal amount of existing 5¼% notes, of which \$68.2 million were tendered and accepted for exchange for an equal principal amount of newly issued 5¼% Convertible Senior Notes due October 6, 2012 (new 5¼% notes). Our 2011 financing cash flow includes payment of \$6.5 million of the remaining principal amount of existing 5¼% notes, which matured in accordance with their terms on October 6, 2011 (Notes 6 and 8).

Our 2010 financing cash flow reflects \$700 million of proceeds from the 5.75% Convertible Perpetual Preferred stock private placements, and \$200 million of proceeds from the 4% senior note issuance, offset by \$6.7 million of related issuance costs and \$15.1 million of preferred stock dividends and \$12.2 million of preferred conversion inducement payments (Notes 6 and 8).

Our 2009 financing cash flow reflects 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).

For additional information regarding our common and preferred stock offerings and our long-term debt, see Notes 6 and 8.

Variable Rate Senior Secured Revolving Credit Facility

During 2011 we entered into a new variable rate senior secured revolving credit facility (credit facility). The credit facility matures on June 30, 2016, provided that by August 16, 2014 our 11.875% senior notes will have been redeemed or refinanced with senior notes with a term extending at least through December 30, 2016; otherwise the maturity date will be August 16, 2014. The credit facility's borrowing capacity is \$150 million, and under certain conditions it may be increased to a capacity of \$300 million with additional lender commitments. There were no borrowings outstanding under the credit facility as of December 31, 2011. 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 a 2007 oil and gas property acquisition, reducing the remaining availability under the facility to \$50 million. For additional information regarding our credit facility, see Note 6.

Senior Notes and Convertible Senior Notes

The following debt instruments were outstanding as of December 31, 2011 (in millions):

	Amount
11.875% senior notes (due 2014)	\$ 300.0
5¼% convertible senior notes, net of \$2.0 discount (due 2012)	66.2
4% convertible senior notes, net of \$12.6 discount (due 2017)	187.4
Credit facility	-
Total debt	\$ 553.6

We may consider opportunities to prepay debt in advance of scheduled maturities. For additional information regarding our outstanding debt terms and related transactions, see Note 6.

Stockholders' Equity

We have 161.3 million shares of common stock outstanding (net of treasury shares) at December 31, 2011. In addition we have 13,999 shares of 8% convertible perpetual preferred stock and 700,000 shares of 5.75% convertible perpetual preferred stock outstanding. As of December 31, 2011, our total stockholders' equity was \$1.7 billion. See Notes 2, 6 and 8 for additional information regarding the descriptions of our outstanding common and preferred stock and the transactions related thereto, including the impact on our results of operations for conversion inducement payments and other preferred dividend charges associated with our convertible preferred stock transactions.

Contractual Obligations and Commitments

In addition to our accounts payable and accrued liabilities ($276.7 million at December 31, 2011), we have other contractual obligations and commitments that will require payments in 2012 and beyond.

The table below summarizes the principal maturities and interest payments associated with our 5¼% notes, 11.875% notes and 4% senior notes, our expected payments for retiree medical costs (Notes 11 and 15), estimates of our current exploration and development commitments and our remaining minimum annual lease payments, according to the time such payments are due, as of December 31, 2011 (in millions):

	Total	2012	2013 to 2014	2015 to 2016	Thereafter
Debt maturities [a]	$ 568.2	$ 68.2	$ 300.0	$ -	$ 200.0
Scheduled interest payment obligations [b]	166.2	50.1	90.2	17.9	8.0
Retirement benefits [c]	4.6	0.7	1.3	1.1	1.5
Oil and gas obligations [d]	268.5	254.5	14.0	-	-
Operating lease obligations [e]	5.8	2.4	3.4	-	-
Total contractual cash obligations	$ 1,013.3	$ 375.9	$ 408.9	$ 19.0	$ 209.5

a. Includes $268.2 million of convertible debt which can be converted to common stock prior to contractual maturity at the discretion of the holders of the securities.
b. Reflects interest and unused commitment fees on the debt balances as of December 31, 2011. Because we did not have any amounts outstanding under our credit facility as of December 31, 2011, 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 senior notes and convertible senior notes is fixed.
c. Includes anticipated payments under our employee retirement health care plan through 2021 (Note 11) and our future reimbursements associated with the contractual liability covering certain of our former sulphur retirees' medical costs (Note 15).
d. These oil and gas obligations include our net working interest share of authorized exploration and development project costs at December 31, 2011 (i.e. project costs for which spending has been formally approved by us and our partners through executed Authorization for Expenditures). Also, included in these amounts is $36.0 million of anticipated expenditures for drilling rig contract charges, portions of which we expect to share with our partners in our exploration program. In addition, includes escrow payments of $5 million per year through 2014 to support the funding requirements related to the 2007 oil and gas acquisition property reclamation obligations (Note 15).
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, 2011, approximately $344.1 million of such obligations were recorded as liabilities, $60.6 million of which was included within current liabilities (Note 15). Additionally, McMoRan is not a party to any off-balance sheet arrangements that require disclosure in the table above.

We are currently meeting our BSEE 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 BSEE requirements are subject to meeting certain financial and other criteria.

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 hydrocarbon commodities storage and handling operation. We obtained a license covering the potential use of the facility for the import of liquefied natural gas (LNG) in early 2007; this license expired in 2012. Commercialization of the project was adversely affected by increased domestic supplies of natural gas, excess LNG regasification capacity and general market conditions. We continue to evaluate other potential commercial options including the use of the MPEH™ assets for handling and storage of various hydrocarbon commodities. As of December 31, 2011, we have incurred approximately $52.9 million of cumulative cash costs associated with our pursuit of the establishment of MPEH™, including $0.5 million in 2011. As of December 31, 2011, we have recognized a liability of $14.3 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 and financing for the MPEH™ project and the ultimate outcome of our efforts to enter into such arrangements on commercially reasonable terms is subject to various uncertainties, many of which are beyond our control.

For information regarding the risks associated with the MPEH™ project, see Item 1A. "Risk Factors" included in this Form 10-K. Also see Note 16 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 BSEE. BSEE 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 previous hurricanes. 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 generally ranging from 0-5 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 when warranted by events. Revisions made for certain properties depending upon the respective circumstances include consideration of the following: (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 current estimates for the timing of the reclamation for the structures comprising our former sulphur facilities; (3) changes in the reclamation costs based on revised estimates of future reclamation work to be performed; and (4) when applicable, 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 4.1 percent to 6.4 percent at December 31, 2011 and 4.6 percent to 9.9 percent at December 31, 2010.

The following table summarizes the estimates of our reclamation obligations at December 31, 2011 and 2010 (in thousands):

	Oil and Gas		Sulphur	
	2011	2010	2011	2010
Undiscounted cost estimates	$ 420,006	$ 467,912	$ 41,006	$ 39,817
Discounted cost estimates	326,394	358,624	17,745	25,266

The following table summarizes the approximate effect of a 1 percent change in the estimated inflation rates and a 5 percent change in the market risk premium rates (in millions):

	Inflation Rate		Market Risk Premium	
	+1%	-1%	+5%	-5%
Oil & Gas reclamation obligations:				
Undiscounted	$ 20.9	$ (20.0)	$ 19.2	$ (13.3)
Discounted	13.5	(12.7)	15.0	(9.2)
Sulphur reclamation obligations:				
Undiscounted	5.8	(5.0)	1.8	(1.8)
Discounted	2.1	(1.9)	0.7	(0.7)

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.

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, 2011, we estimate that our depletion, depreciation and amortization expense for 2011 would have decreased by approximately $16.2 million, while a 10 percent decrease in estimated proved reserves for each property would have resulted in an approximate $16.9 million increase in our depletion, depreciation and amortization expense for 2011. Changes in our estimates of proved reserves may also affect our assessment of asset impairment. We believe that if our aggregate estimated proved reserves were significantly 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 adjusted 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 2012, a change of $1.00 per Mcf in the average realized price for natural gas and natural gas liquids would have an approximate $34 million net impact on our revenues and pre-tax operating results and a $10 per barrel change in average oil realized prices would have an approximate $22 million net impact on our revenues and pre-tax operating results. Based on our currently projected sales volumes for 2012, a 10 percent fluctuation in natural gas and natural gas liquid sales volumes would impact our revenues by approximately $12 million and our pre-tax operating results by approximately $3 million, while a 10 percent fluctuation in our oil sales volumes would have an approximate $24 million impact on revenues and an approximate $20 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.

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. We do not expect the adoption of any accounting standards in 2012 to have a material impact to our financial statements.

CAUTIONARY STATEMENT

Management's Discussion and Analysis of Financial Condition and Results of Operations contain forward-looking statements in which we discuss certain of our expectations regarding future operational and financial performance. Forward-looking statements are all statements other than statements of historical facts, such as those statements regarding potential oil and gas discoveries, oil and gas exploration, development and production activities and costs, amounts and timing of capital expenditures, reclamation, indemnification and environmental obligations and costs, potential quarterly and annual production and flow rates, reserve estimates, projected operating cash flows and liquidity, and statements about the potential opportunities and benefits presented by the recent property acquisition, including expectations regarding reserve estimates and production rates. The words "anticipates," "may," "can," "plans," "believes," "estimates," "expects," "projects," "intends," "likely," "will," "should," "to be," and any similar expressions and/or statements that are not historical facts are intended to identify those assertions as forward-looking statements.

We caution readers that forward-looking statements are not guarantees of future performance or exploration and development success, and our actual exploration experience and future financial results may differ materially from those anticipated, projected or assumed in the forward-looking statements. Important factors that may cause our actual results to differ materially from those anticipated by the forward-looking statements include, but are not limited to, those associated with general economic and business conditions, failure to realize expected value creation from acquired properties, variations in the market demand for, and prices of, oil and natural gas, drilling results, unanticipated fluctuations in flow rates of producing wells due to mechanical or operational issues (including those experienced at wells operated by third parties where we are a participant), changes in oil and natural gas reserve expectations, the potential adoption of new governmental regulations, unanticipated hazards as to which we have limited or no insurance coverage, failure of third party partners to fulfill their capital and other commitments, the ability to satisfy future cash obligations and environmental costs, adverse conditions, such as high temperatures and pressure that could lead to mechanical failures or increased costs, the ability to retain current or future lease acreage rights, the ability to satisfy future cash obligations and environmental costs, access to capital to fund drilling activities, as well as other general exploration and development risks and hazards, and other factors described in more detail under "Risk Factors" in Item 1A. of this Form 10-K.

Investors are cautioned that many of the assumptions upon which our forward-looking statements are based are likely to change after our forward-looking statements are made, including for example the market prices of oil and natural gas, which we cannot control, and production volumes and costs, some aspects of which we may or may not be able to control. Further, we may make changes to our business plans that could or will affect our results. We caution investors that we do not intend to update our forward-looking statements more frequently than quarterly, notwithstanding any changes in our assumptions, changes in our business plans, our actual experience, or other changes, and we undertake no obligation to update any forward-looking statements.

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.

James R. Moffett
Co-Chairman of the Board,
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 (McMoRan) internal control over financial reporting as of December 31, 2011, 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, 2011, 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, 2011 and 2010, 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, 2011, and our report dated February 29, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana
February 29, 2012

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, 2011 and 2010, 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, 2011. 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, 2011 and 2010, and the consolidated results of its operations and its cash flow for each of the three years in the period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), McMoRan Exploration Co.'s internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 29, 2012, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana
February 29, 2012

McMoRan EXPLORATION CO.
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2011	2010
	(In thousands, except share related amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 568,763	$ 905,684
Accounts receivable	72,085	86,516
Inventories	36,274	38,461
Prepaid expenses	9,103	15,478
Current assets from discontinued operations, including restricted cash of $473	682	702
Total current assets	686,907	1,046,841
Property, plant and equipment, net	2,181,926	1,785,607
Restricted cash and other	61,617	53,975
Deferred financing costs	8,325	9,952
Long-term assets from discontinued operations	439	2,989
Total assets	$ 2,939,214	$ 2,899,364
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 115,832	$ 102,658
Accrued liabilities	160,822	99,363
Accrued interest and dividends payable	14,448	6,768
Current portion of accrued oil and gas reclamation costs	58,810	120,970
5¼% convertible senior notes	66,223	74,720
Current liabilities from discontinued operations, including sulphur reclamation costs	5,264	13,765
Total current liabilities	421,399	418,244
11.875% senior notes	300,000	300,000
4% convertible senior notes	187,363	185,256
Accrued oil and gas reclamation costs	267,584	237,654
Other long-term liabilities	20,886	16,596
Other long-term liabilities from discontinued operations, including sulphur reclamation costs	19,018	17,277
Total liabilities	$ 1,216,250	$ 1,175,027
Commitments and contingencies (Note 15)		

McMoRan EXPLORATION CO.
CONSOLIDATED BALANCE SHEETS
(Continued)

	December 31, 2011	December 31, 2010
	(In thousands, except share related amounts)	
Stockholders' equity:		
Preferred stock, par value $0.01, 50,000,000 shares authorized, 713,999 and 722,063 shares issued and outstanding (liquidation preference), respectively (Note 8)	$ 713,999	$ 722,063
Common stock, par value $0.01, 300,000,000 shares authorized, 163,940,835 shares and 159,797,352 shares issued and outstanding, respectively	1,639	1,598
Capital in excess of par value of common stock	2,178,775	2,156,430
Accumulated deficit	(1,123,449)	(1,107,481)
Accumulated other comprehensive income (loss)	216	(97)
Common stock held in treasury, 2,611,591 shares and 2,609,427 shares, at cost, respectively	(48,216)	(48,176)
Total stockholders' equity	1,722,964	1,724,337
Total liabilities and stockholders' equity	$ 2,939,214	$ 2,899,364

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

McMoRan EXPLORATION CO.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2011	2010	2009
	(In thousands, except per share amounts)		
Revenues:			
Oil and natural gas	$ 542,310	$ 418,816	$ 422,976
Service	13,104	15,560	12,459
Total revenues	555,414	434,376	435,435
Costs and expenses:			
Production and delivery costs	206,319	182,790	193,025
Depletion, depreciation and amortization expense	307,902	282,062	313,980
Exploration expenses	81,742	42,608	94,281
Gain on oil and gas derivative contracts	-	(4,240)	(17,394)
General and administrative expenses	49,471	51,529	42,954
Main Pass Energy Hub™ costs	588	1,011	1,615
Insurance recoveries (Note 4)	(91,076)	(38,944)	(24,592)
Gain on sale of oil and gas properties	(900)	(3,455)	-
Total costs and expenses	554,046	513,361	603,869
Operating income (loss)	1,368	(78,985)	(168,434)
Interest expense, net	(8,782)	(38,216)	(42,943)
Other income, net	810	225	4,043
Loss from continuing operations before income taxes	(6,604)	(116,976)	(207,334)
Income tax benefit (expense)	-	-	2,445
Loss from continuing operations	(6,604)	(116,976)	(204,889)
Loss from discontinued operations	(9,364)	(3,366)	(6,097)
Net loss	(15,968)	(120,342)	(210,986)
Preferred dividends and inducement payments for early conversion of preferred stock (Note 8)	(42,800)	(77,101)	(14,332)
Net loss applicable to common stock	$ (58,768)	$ (197,443)	$ (225,318)
Basic and diluted net loss per share of common stock:			
Net loss from continuing operations	$(0.31)	$(2.04)	$(2.79)
Net loss from discontinued operations	(0.06)	(0.04)	(0.08)
Net loss per share of common stock	$(0.37)	$(2.08)	$(2.87)
Average common shares outstanding:			
Basic and diluted	159,216	95,125	78,625

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

McMoRan EXPLORATION CO.
CONSOLIDATED STATEMENTS OF CASH FLOW

	Years Ended December 31,		
	2011	2010	2009
		(In thousands)	
Cash flow from operating activities:			
Net loss	$ (15,968)	$ (120,342)	$ (210,986)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Loss from discontinued operations	9,364	3,366	6,097
Depletion, depreciation and amortization expense	307,902	282,062	313,980
Exploration drilling and related expenditures	42,339	14,526	61,504
Compensation expense associated with stock-based awards	18,325	18,707	14,193
Amortization of deferred financing costs	5,881	3,729	3,725
Change in fair value of oil and gas derivative contracts	-	6,800	28,631
Reclamation expenditures, net of prepayments by third parties	(150,021)	(115,133)	(45,885)
Increase in restricted cash	(5,012)	(12,298)	(15,049)
Gain on sale of oil and gas properties	(900)	(3,455)	-
Other	(318)	227	(720)
(Increase) decrease in working capital:			
Accounts receivable	(22,996)	(17,483)	30,476
Accounts payable and accrued liabilities	45,944	30,223	(33,281)
Inventories	2,187	10,895	(16,535)
Prepaid expenses	5,303	(1,377)	743
Net cash provided by continuing operations	242,030	100,447	136,893
Net cash used in discontinued operations	(14,982)	(2,217)	(5,728)
Net cash provided by operating activities	227,048	98,230	131,165
Cash flow from investing activities:			
Exploration, development and other capital expenditures	(509,494)	(217,252)	(138,015)
Proceeds from sale of oil and gas properties	900	2,920	-
Acquisition of oil and gas properties, net	(9,520)	(86,134)	-
Net cash used in continuing activities	(518,114)	(300,466)	(138,015)
Net cash from discontinued operations	-	-	-
Net cash used in investing activities	$ (518,114)	$ (300,466)	$ (138,015)

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

	Years Ended December 31,		
	2011	2010	2009
		(In thousands)	
Cash flow from financing activities:			
Proceeds from the sale of 5.75% convertible perpetual preferred stock	$ -	$ 700,000	$ -
Proceeds from the sale of 4% convertible senior notes	-	200,000	-
Dividends paid and inducement payments on early conversion of convertible preferred stock	(37,951)	(27,306)	(13,469)
Payment of 5¼% convertible senior notes	(6,543)	-	-
Credit facility refinancing fees	(1,745)	-	-
Debt and equity issuance costs	(562)	-	-
Proceeds from exercise of stock options and other	946	497	-
Costs associated with the sale of 5.75% convertible perpetual preferred stock and sale of 4% convertible senior notes	-	(6,689)	-
Net proceeds from sale of common stock	-	-	84,976
Net proceeds from sale of preferred stock	-	-	83,275
Net cash provided by (used in) continuing operations	(45,855)	866,502	154,782
Net cash from discontinued operations	-	-	-
Net cash provided by (used in) financing activities	(45,855)	866,502	154,782
Net increase (decrease) in cash and cash equivalents	(336,921)	664,266	147,932
Cash and cash equivalents at beginning of year	905,684	241,418	93,486
Cash and cash equivalents at end of year	$ 568,763	$ 905,684	$ 241,418
Interest paid	$ 47,473	$ 44,543	$ 43,059
Income taxes paid	$ -	$ 63	$ 2,332
Supplemental non-cash investing & financing activities:			
Issuance of 2.8 million and 51 million shares of common stock and other non-cash purchase price consideration related to property acquisitions in 2011 and 2010, respectively	$ 39,123	$ 926,010	$ -
Accrued debt and preferred stock offering costs	$ -	$ 1,006	$ -

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

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

	Years Ended December 31,		
	2011	2010	2009
	(In thousands, except share & per share amounts)		
8% convertible perpetual preferred stock:			
Balance at beginning of year, representing 22,063 shares in 2011, 86,250 shares in 2010 and no shares in 2009	$ 22,063	$ 86,250	$ -
Shares converted in privately negotiated transactions, representing 8,064 shares in 2011 and 64,187 in 2010	(8,064)	(64,187)	-
Shares issued in equity offering, representing 86,250 shares	-	-	86,250
Balance at end of year, representing 13,999 shares in 2011, 22,063 shares in 2010 and 86,250 shares in 2009	13,999	22,063	86,250
5.75% convertible perpetual preferred stock:			
Balance at beginning of year, representing 700,000 shares in 2011 and no shares in 2010 or 2009	700,000	-	-
Shares issued in equity offering, representing 700,000 shares in 2010	-	700,000	-
Balance at end of year, representing 700,000 shares in 2011 and 2010 and no shares in 2009	700,000	700,000	-
6¾% mandatorily convertible preferred stock:			
Balance at beginning of year, representing no shares in 2011 and 1,589,340 shares in 2010 and 2009	-	158,934	158,934
Shares converted representing 1,589,340 shares in 2010	-	(158,934)	-
Balance at end of year, representing no shares in 2011 and 2010 and 1,589,340 shares in 2009	-	-	158,934
Common stock:			
Balance at beginning of year, representing 159,797,352 shares in 2011, 88,555,685 shares in 2010 and 72,981,734 shares in 2009	1,598	885	730
Shares issued to Plains Exploration & Production Company in 2010 (Notes 2 and 8), representing 51,000,000 shares	-	510	-
Preferred stock conversions, representing 1,178,514 shares in 2011 and 20,061,622 in 2010	12	201	-
Shares issued in equity offering, representing 2,835,158 shares (at $12.36 per share) in 2011 and 15,547,400 shares (at $5.75 per share) in 2009 (Note 8)	28	-	155
Exercise of stock options and other, representing 129,811 in 2011, 180,045 shares in 2010 and 26,551 shares in 2009	1	2	-
Balance at end of year, representing, 163,940,835 shares in 2011, 159,797,352 shares in 2010 and 88,555,685 shares in 2009	$ 1,639	$ 1,598	$ 885

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

	Years Ended December 31,		
	2011	2010	2009
	(In thousands, except share and per share amounts)		
Capital in excess of par value:			
Balance at beginning of year	$ 2,156,430	$ 1,053,684	$ 971,977
Costs associated with preferred stock equity offerings	275	(5,945)	(2,975)
Common stock issued, net of offering costs	34,996	875,670	84,821
Intrinsic value – convertible debt and equity beneficial conversion options (Notes 6 and 8)	-	66,375	-
Debt discount on 5¼% convertible senior notes (Note 6)	2,550	-	-
Preferred stock conversions	8,052	222,921	-
Stock-based compensation expense	18,327	18,707	14,193
Exercise of stock options	945	2,119	-
Preferred stock dividends, inducement payments and beneficial conversion option	(42,800)	(77,101)	(14,332)
Balance at end of year	2,178,775	2,156,430	1,053,684
Accumulated deficit:			
Balance at beginning of year	(1,107,481)	(987,139)	(776,153)
Net loss	(15,968)	(120,342)	(210,986)
Balance at end of year	(1,123,449)	(1,107,481)	(987,139)
Accumulated other comprehensive income (loss):			
Balance at beginning of year	(97)	(346)	(22)
Amortization of previously unrecognized pension components, net	(40)	(40)	(40)
Change in unrecognized net gains (losses) of pension plans	353	289	(284)
Balance at end of year	216	(97)	(346)
Common stock held in treasury:			
Balance at beginning of year, representing 2,609,427 shares in 2011, 2,511,132 shares in 2010 and 2,508,660 in 2009	(48,176)	(46,460)	(46,443)
Tender of 2,164 shares in 2011, 98,295 shares in 2010 and 2,472 shares in 2009 associated with the exercise of stock options and the vesting of restricted stock	(40)	(1,716)	(17)
Balance at end of year, representing 2,611,591 shares in 2011, 2,609,427 shares in 2010 and 2,511,132 shares in 2009	(48,216)	(48,176)	(46,460)
Total stockholders' equity	$ 1,722,964	$ 1,724,337	$ 265,808

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

McMoRan EXPLORATION CO.
NOTES TO 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 is to maximize the value of the offshore structures used in the former sulphur operations, which may include the pursuit of a multifaceted energy services facility, including the potential development of a hydrocarbon commodities storage and handling operation at the Main Pass Energy Hub™ (MPEH™) project located at Main Pass Block 299 (Main Pass) in the Gulf of Mexico.

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 2011, none of which impacted the consistency of presentation, are discussed below under the caption "New Accounting Standards."

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

On December 30, 2010, MOXY completed an acquisition of oil and gas properties (Note 2). McMoRan's consolidated financial statements include the acquisition cost and results of operations of the acquired properties prospectively from the closing date.

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, primarily offshore in the Gulf of Mexico and onshore in the Gulf Coast region (primarily Louisiana and Texas).

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 (primarily ethane, propane, butane and natural gasolines) 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 require 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 15).

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 $1.3 million at December 31, 2011 and $1.1 million at December 31, 2010, consisting of crude oil production from Main Pass. Materials and supplies inventory totaled $34.9 million at December 31, 2011 and $37.4 million at December 31, 2010 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. There were no required reductions in the carrying value of McMoRan's inventories during 2011 or 2010.

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 use 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 use 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 revised whenever required but, at a minimum, are assessed semi-annually. Any such revisions are accounted for prospectively as a change in accounting estimate.

- The costs of maintenance and repairs 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 $47.4 million in 2011, $10.1 million in 2010 and $3.9 million in 2009.

Sulphur. Note 10 includes results associated with McMoRan's discontinued operations, which are reflected within the caption "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, a reduction of the carrying amount to estimated fair value is required. McMoRan estimates the fair value of its properties (derived from Level 3 inputs) 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 period-end 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 market participants' expected rates of return for similar type assets if acquired under current market conditions.

The determination of oil and 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 in estimated reserves and related estimates of future cash flows, and these variations may be substantial. If the capitalized costs of an individual oil and gas property exceed 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, 2011, McMoRan had natural gas imbalance receivables valued at $4.2 million and liabilities valued at $4.6 million for over deliveries. At December 31, 2010, McMoRan had natural gas imbalance receivables valued at $5.7 million and liabilities valued at $6.7 million for over deliveries.

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 expense line item in the accompanying consolidated financial statements.

McMoRan's service revenues have been generated primarily through fees for processing third-party oil and gas production, 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 15).

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 13).

Financial Instruments and Contracts. Based on its assessment of market conditions, McMoRan may enter into financial contracts to manage certain risks resulting from fluctuations in oil and natural gas prices. Costs or premiums and gains or losses on contracts meeting deferral criteria are recognized with the hedged transactions. Also, gains or losses are recognized if the hedged transaction is no longer expected to occur or if deferral criteria are not met. McMoRan monitors 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 were subject to mark-to-market fair value adjustments, the impact of which was recognized immediately in McMoRan's operating results. McMoRan recorded 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 was 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. All remaining derivative contract positions matured on December 31, 2010 (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 (Notes 8 and 9).

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 11).

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 12).

New Accounting Standards. In May 2011, the Financial Accounting Standards Board (FASB) issued an Accounting Standards Update (ASU) in connection with guidance for fair value measurements and disclosures. This ASU clarifies the FASB's intent on current guidance, modifies and changes certain guidance and principles, and expands disclosures concerning Level 3 fair value measurements in the fair value hierarchy (including quantitative information about significant unobservable inputs within Level 3 of the fair value hierarchy). In addition, this ASU requires disclosure of the fair value hierarchy for assets and liabilities not measured at fair value in the statement of financial position, but whose fair value is required to be disclosed. This ASU is effective for interim and annual reporting periods beginning after December 15, 2011, and early application is not permitted. The adoption of this accounting standard is not expected to have an impact on McMoRan's financial position or results of operations.

In June 2011, FASB issued an ASU in connection with guidance on the presentation of comprehensive income. The objective of this ASU is to improve the comparability, consistency and transparency of financial reporting and to increase the prominence of items reported in other comprehensive income. This ASU requires an entity to present the components of net income and other comprehensive income and total comprehensive income (includes net income) either in a single continuous statement of comprehensive income or in two separate but consecutive statements. This ASU eliminates the option to present the components of other comprehensive income as part of the statement of equity, but does not change the items that must be reported in other comprehensive income. This ASU is effective for interim and annual reporting periods beginning after December 15, 2011, and early adoption is permitted. McMoRan has determined it will present comprehensive income as a separate statement beginning in the first quarter of 2012. In December 2011, FASB deferred the effective date for the requirement in this ASU for presenting reclassification adjustments for each component of accumulated other comprehensive income in both net income and other comprehensive income on the face of the financial statements. The adoption of this accounting standard is only expected to have an impact on the financial statement presentation of comprehensive income as a separate statement and is not expected to have an impact on McMoRan's financial position or results of operations.

2. ACQUISITION OF GULF OF MEXICO SHELF PROPERTIES

On September 8, 2011, McMoRan acquired Whitney Exploration LLC's (Whitney) 2.97% working interest in Davy Jones and 2% working interest in Blackbeard East. Under the terms of the transaction, McMoRan issued approximately 2.8 million shares of its common stock and paid $10 million in cash to Whitney for these interests relating to drilling projects in process. McMoRan's common stock price on the closing date was $12.36 per share. The fair value of the interests acquired approximated $49 million. The acquisition of Whitney's interests had no material impact to McMoRan's statements of operations on a pro forma basis.

On December 30, 2010, McMoRan completed the $1 billion acquisition of Plains Exploration & Production Company's (PXP) shallow water Gulf of Mexico shelf assets (PXP Acquisition). Under the terms of the transaction, McMoRan issued 51 million shares of its common stock and paid $75.0 million in cash to PXP. In addition, the purchase price included $45.5 million associated with estimated revenues, expenses and capital expenditures attributable to the properties from the August 1, 2010 effective date through the December 30, 2010 closing date, and the assumption of approximately $8.8 million of related asset retirement obligations. The substantial majority of properties acquired from PXP represented their interests in certain deep gas and ultra-deep exploration projects that were jointly owned by McMoRan and PXP prior to the transaction. McMoRan incurred approximately $9.4 million in transaction related costs for the PXP Acquisition included in general and administrative expenses. Concurrent with the PXP Acquisition, McMoRan issued $700 million of 5.75% Convertible Perpetual Preferred Stock (5.75% preferred stock) and $200 million of 4% Convertible Senior Notes (4% senior notes) to certain investors (Notes 6 and 8).

The following table summarizes the final PXP Acquisition allocation of purchase price to the acquired assets and assumed liabilities based on valuation estimates of fair value (derived from Level 3 fair value inputs) (in thousands, except share data):

Property, Plant and Equipment	
Cash consideration	
Purchase price terms	$ 75,000
Post-effective date cash items	5,897
Stock consideration	
51 million shares based on McMoRan's closing stock price of $17.18 per share on December 30, 2010	876,180
Post-effective date non-cash items and other	38,114
Assumed asset retirement obligations	8,829
Acquired property, plant and equipment	$ 1,004,020
Inventory (cash consideration)	$ 1,538

The following unaudited pro forma financial information assumes McMoRan acquired the properties from PXP and consummated the related financing transactions effective January 1, 2009 (in thousands, except per share data):

	(Pro Forma, Unaudited) Years Ended December 31,	
	2010	2009
Revenues	$ 550,808	$ 562,726
Operating loss	(58,331)	(175,565)
Net loss to common shareholders	(175,771)	(334,682)
Basic and diluted net loss per share of common stock	(1.20)	(2.58)

The pro forma operating loss and net loss amounts reflected above include pro forma adjustments for certain exploration and asset impairment charges that McMoRan would have recorded under the successful efforts method of accounting assuming the PXP Acquisition had been consummated on January 1, 2009. Those amounts include $9.7 million and $39.7 million of non-productive exploratory drilling costs in 2010 and 2009, respectively, and $26.8 million of asset impairment charges in 2010. In addition, $9.0 million of transaction-related costs for the PXP Acquisition and $51.6 million of preferred dividend charges related to the issuance of the 5.75% preferred stock (Note 8) has been reflected in 2009 rather than 2010 under the pro forma assumption that the PXP Acquisition and related financing transactions occurred as of January 1, 2009.

The fair value of acquired oil and gas properties was determined using estimated future cash flows based upon proved and risk-adjusted unproved oil and gas reserves, as estimated by a combination of independent and internal McMoRan reserve engineers. Future cash flows were determined using published forward market prices net of estimated future production and development costs. The future net cash flows were discounted using a discount factor that considered investors' expected rates of return for similar assets.

3. ACCOUNTS RECEIVABLE AND MAJOR CUSTOMERS

The components of accounts receivable follow (in thousands):

	December 31, 2011	December 31, 2010
Accounts receivable:		
Customers	$ 44,459	$ 42,138
Joint interest partners	23,354	32,429
Other	4,272	11,949
Total accounts receivable	$ 72,085	$ 86,516

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, 2011 is as follows:

Individual Customer	Years Ended December 31, 2011	2010	2009
A	41 %	35 %	32 %
B	16	14	15
C	13	<10	<10
D	<10	<10	10

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, 2011	December 31, 2010
Oil and gas property, plant and equipment	$ 4,124,111	$ 3,491,386
Other	30	31
	4,124,141	3,491,417
Accumulated depletion, depreciation and amortization	(1,942,215)	(1,705,810)
Property, plant and equipment, net	$ 2,181,926	$ 1,785,607

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

	Years Ended December 31, 2011	2010	2009
Depletion and depreciation expense	$ 165,277	$ 148,358	$ 205,479
Accretion expense (Note 15)	71,496	26,525	33,186
Impairment charges/losses	71,129	107,179	75,315
Total depletion, depreciation and amortization expense	$ 307,902	$ 282,062	$ 313,980

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 recorded impairment charges during the year ended December 31, 2011 of $71.1 million primarily due to well performance issues, the decline in market prices for natural gas, and the impact of increased capitalized costs from asset retirement obligation adjustments for certain properties

(Note 15). During the years ended December 31, 2010 and 2009 McMoRan recorded impairment charges of $107.2 million and $75.3 million, respectively, due largely to declines in market prices for natural gas during those years and, with respect to certain properties, as a result of negative reserve revisions from well performance issues.

As discussed above, declines in market prices for primarily 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 recent years 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 impacted many companies' Gulf of Mexico operations prior to making landfall on the Louisiana and Texas coasts in September 2008. Although there was no significant damage to McMoRan's properties resulting from Hurricane Gustav, 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 of approximately $200 million related to incurred repair costs, property impairments and additional estimated reclamation costs associated with the damaged properties. In December 2011, McMoRan reached a settlement with its insurance underwriters to finalize all outstanding claims from the 2008 hurricane events. McMoRan recognized net insurance recoveries of $91.1 million in 2011, $38.9 million in 2010 and $24.6 million in 2009.

5. OTHER ASSETS AND OTHER LIABILITIES

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

	December 31, 2011			December 31, 2010		
	Gross Carrying Amount	Accumulated Amortization	Net	Gross Carrying Amount	Accumulated Amortization	Net
11.875% Senior Notes (due November 2014)	$ 8,055	$ (4,753)	$ 3,302	$ 8,055	$ (3,602)	$ 4,453
Revolving Credit Facility (matures June 2016)	13,122	(9,437)	3,685	11,377	(7,961)	3,416
5¼% Convertible Senior Notes (due October 2012)	6,264	(6,264)	-	6,243	(5,909)	334
4% Convertible Senior Notes (due December 2017)	1,563	(225)	1,338	1,750	(1)	1,749
	$ 29,004	$ (20,679)	$ 8,325	$ 27,425	$ (17,473)	$ 9,952

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

	December 31,	
	2011	2010
Advances from third parties for future abandonment costs (Note 15)	$ 12,542	$ 7,561
Employee postretirement medical liability (Note 11)	3,676	3,916
Liability for management services (Note 14)	2,873	2,839
Nonqualified pension plan liability	1,453	1,845
Accrued workers compensation and group insurance	342	435
	$ 20,886	$ 16,596

6. LONG-TERM DEBT

The components of McMoRan's long-term debt follow (in thousands):

	December 31, 2011	December 31, 2010
11.875% senior notes (due 2014)	$ 300,000	$ 300,000
5¼% convertible senior notes, net of discount of $1,954 and $0 (due 2012)	66,223	74,720
4% convertible senior notes, net of discount of $12,637 and $14,744 (due 2017)	187,363	185,256
Credit facility	-	-
Total debt	553,586	559,976
Less current maturities	(66,223)	(74,720)
Long-term debt	$ 487,363	$ 485,256

McMoRan's scheduled debt maturities are $68.2 million in 2012; none in 2013; $300 million in 2014; none in 2015 or 2016; and $200 million thereafter.

Variable Rate Senior Secured Revolving Credit Facility

During 2011 McMoRan entered into a new variable rate senior secured revolving credit facility (credit facility). The credit facility matures on June 30, 2016, provided that by August 16, 2014 McMoRan's 11.875% senior notes will have been redeemed or refinanced with senior notes with a term extending at least through 2016; otherwise the maturity date will be August 16, 2014. The credit facility's borrowing capacity is $150 million, and under certain conditions it may be increased to a capacity of $300 million with additional lender commitments. There were no borrowings outstanding under the credit facility as of December 31, 2011. After giving effect to a $100 million letter of credit outstanding as surety support to a third party associated with reclamation obligations, availability totaled $50 million.

Availability under the credit facility is subject to a borrowing base calculated from estimates of MOXY's oil and natural gas reserves, which is subject to redetermination by its lenders semi-annually each April and October. The 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 credit facility currently accrues at London Interbank Offered Rate (LIBOR) plus 2.50 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. There were no borrowings under the credit facility in 2011, 2010 or 2009. Interest expense on the credit facility (including amortization of deferred financing costs and other facility fees) totaled $4.3 million in 2011, $6.2 million in 2010 and $5.7 million in 2009.

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 credit 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, 2011.

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 a previous 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 18). McMoRan may redeem some or all of these notes at its option 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 2011, 2010 and 2009 totaled $36.8 million, including amortization of related deferred financing costs of $1.2 million in each of those years. The estimated fair value of the 11.875% senior notes was approximately $318.0 million at December 31, 2011 and $331.5 million at December 31, 2010.

4% Convertible Senior Notes
On December 30, 2010, McMoRan completed a private placement of $200 million of 4% convertible senior notes due December 30, 2017 concurrent with the 5.75% convertible preferred stock offerings (Note 8) and the PXP Acquisition (Note 2). The 4% senior notes are unsecured with semi-annual interest payments payable on February 15 and August 15 of each year. The 4% senior notes are convertible, at the option of the holder, at any time on or prior to maturity, into shares of McMoRan common stock at a conversion rate of 62.5 shares of McMoRan common stock, which is equal to an initial conversion price of $16.00 per share of McMoRan common stock per $1,000 principal amount of the notes. The conversion rate is subject to adjustment upon the occurrence of certain events. The 4% senior notes are redeemable for cash by McMoRan beginning December 30, 2015 under certain conditions.

The terms of the 4% senior notes were negotiated in September 2010, and the closing for these notes was contingent upon the approval by McMoRan's shareholders of Freeport-McMoRan Copper & Gold Inc.'s (FCX) investment in the 5.75% preferred stock offering (Note 8) and the PXP Acquisition. The Notes closed on December 30, 2010, the date of shareholder approval of the other concurrent transactions. Because the value of McMoRan's common stock on the closing date ($17.18 per share) exceeded the conversion price ($16 per share) for the convertible notes issued, the 4% senior notes included a beneficial conversion option. With respect to the 4% senior notes, the intrinsic value of the beneficial conversion option was recognized as a $14.8 million debt discount and a $14.8 million increase to McMoRan's additional paid-in-capital, which is being accreted through McMoRan's earnings as adjustments to interest expense through the debt maturity date. McMoRan incurred approximately $1.6 million of debt issuance costs associated with the 4% senior notes. The estimated fair value of the 4% senior notes was approximately $232.6 million at December 31, 2011 and $255.0 million at December 31, 2010.

5¼% Convertible Senior Notes
On October 6, 2004, McMoRan completed a private placement of $140 million of 5¼% convertible senior notes due October 6, 2011 (existing 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. Interest expense totaled $4.1 million for the year ended December 31, 2011 and $4.4 million for the years ended December 31, 2010 and 2009, including amortization of deferred financing costs of $0.3 million in 2011 and $0.4 million in 2010 and 2009. 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 October 6, 2011, McMoRan completed an offer to exchange up to $74.7 million aggregate principal amount of existing 5¼% notes. Existing 5¼% notes in the principal amount of $68.2 million were tendered and accepted for exchange for an equal principal amount of newly issued 5¼% Convertible Senior Notes due October 6, 2012 (new 5¼% notes). McMoRan repaid $6.5 million of the remaining principal amount of existing 5¼% notes, which matured in accordance with their terms on October 6, 2011. The terms of the new 5¼% notes are substantially the same as the terms of the previous 5¼% notes, except that the new 5¼% notes have a maturity date of October 6, 2012. The impact of this exchange transaction, which was recorded as a modification of debt in the fourth quarter of 2011, resulted in the recognition of an approximate $2.6 million debt discount related to the fair value of the instruments' embedded conversion option that is being accreted as a component of interest expense over the one year term of the new 5¼% notes.

The estimated fair value of the 5¼% notes was $73.6 million at December 31, 2011 and $89.3 million at December 31, 2010.

7. DERIVATIVE CONTRACTS

In connection with the closing of the 2007 oil and gas property acquisition 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.

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 were 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,	
	2010	2009
Realized (gain) loss		
Gas puts	$ (1,453)	$ (6,700)
Oil puts	121	238
Gas swaps	(10,754)	(33,818)
Oil swaps	1,046	(5,745)
Total realized gain	(11,040)	(46,025)
Unrealized (gain) loss		
Gas puts	578	1,167
Oil puts	(76)	929
Gas swaps	7,536	18,002
Oil swaps	(1,238)	8,533
Total unrealized loss	6,800	28,631
Net gain on oil and gas derivative contracts	$ (4,240)	$ (17,394)

All remaining derivative contract positions matured on December 31, 2010.

8. COMMON STOCK AND PREFERRED STOCK OFFERINGS

On September 8, 2011, McMoRan issued approximately 2.8 million shares of its common stock in connection with acquiring Whitney's working interests in Davy Jones and Blackbeard East, and on December 30, 2010, McMoRan issued 51 million shares of its common stock in connection with the PXP Acquisition (Note 2).

On December 30, 2010, McMoRan completed the private placement of $700 million of 5.75% convertible perpetual preferred stock (5.75% Preferred Stock) concurrent with the 4% senior note offering (Note 6) and the PXP Acquisition (Note 2). FCX, an affiliate of McMoRan (Note 14), purchased $500 million of the 5.75% Preferred Stock, and $200 million of the 5.75% Preferred Stock was purchased by institutional investors.

The 5.75% preferred stock is recorded at the liquidation preference value ($1,000 per share). Cumulative annual dividends accrue at 5.75% of the liquidation preference, payable quarterly on February 15, May 15, August 15 and November 15 of each year, which commenced on February 15, 2011. The 5.75% preferred stock is convertible, at the option of the holder, at any time into shares of McMoRan common stock at a conversion rate of 62.5 shares of McMoRan common stock per $1,000 liquidation preference of the 5.75% preferred stock, which is equal to an initial conversion price of $16.00

per share. On or after three years following the date of issuance, McMoRan may redeem some or all of the 5.75% preferred stock under certain conditions.

The terms of the 5.75% preferred stock were negotiated in September 2010 and closing for the transaction was subject to McMoRan shareholder approval. The transaction closed on December 30, 2010, the date of shareholder approval. Because the value of McMoRan's common stock on the closing date ($17.18 per share) exceeded the conversion price ($16 per share) for the convertible instruments issued, the 5.75% preferred stock included a beneficial conversion option. The intrinsic value of the beneficial conversion option associated with the 5.75% preferred stock was recognized by McMoRan at the date of closing as a preferred stock discount and related preferred stock dividend resulting in a $51.6 million increase to additional paid-in-capital and a $51.6 million reduction to income applicable to common shareholders. McMoRan incurred approximately $5.7 million of offering costs associated with the 5.75% preferred stock.

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.

The 8% preferred stock is recorded at the liquidation preference value ($1,000 per share), and dividends are paid quarterly. 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 2010, McMoRan privately negotiated the induced conversion of approximately 64,200 shares of its 8% preferred stock with a liquidation preference of $64.2 million into approximately 9.4 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 the 8% preferred stock, McMoRan paid an aggregate of $12.2 million in cash and recorded such payments as preferred dividends.

In 2011, McMoRan privately negotiated the induced conversion of approximately 8,100 shares of its 8% preferred stock with a liquidation preference of $8.1 million into approximately 1.2 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 conversion of these shares of 8% preferred stock, McMoRan paid an aggregate of $1.5 million in cash and recorded such payments as preferred dividends. At December 31, 2011, approximately 14,000 shares of McMoRan 8% preferred stock remained 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 6¾% preferred stock automatically converted on November 15, 2010 into 10.7 million shares of McMoRan common stock.

9. EARNINGS PER SHARE

McMoRan had a net loss from continuing operations for each of the three years in the period ending December 31, 2011. 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 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 5.75% preferred stock, 8% preferred stock, 6¾% preferred stock, 4% senior 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,		
	2011	2010	2009
In-the-money stock options [a, b]	1,332	2,938	-
Shares issuable upon assumed conversion of:			
5.75% preferred stock [c]	43,750	120	-
8% preferred stock [d]	2,175	2,875	6,631
6¾% preferred stock [e]	-	1,317	12,817
4% senior notes [f]	12,500	34	-
5¼% notes [g]	4,414	4,508	4,508

a. McMoRan uses the treasury stock method to determine the amount of in-the-money stock options 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. Amount represents total equivalent common stock shares assuming conversion of 5.75% preferred stock (Note 8). The 2010 amount is reduced from the total 43.8 million equivalent shares that would have been issued upon conversion to reflect the weighted average impact of the number of days the preferred stock was outstanding in 2010. Preferred dividends and other charges totaled $40.1 million in 2011 and $51.8 million in 2010.
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 and inducement payments totaled $2.7 million in 2011, $14.9 million in 2010 and $3.6 million in 2009.
e. Amount represents total equivalent common stock shares assuming conversion of 6¾% preferred stock (Note 8). Preferred dividends, amortization of convertible preferred stock issuance costs and inducement payments for the early conversion of preferred stock totaled $9.4 million in 2010 and $10.7 million in 2009.
f. Amount represents total equivalent common stock shares assuming conversion of 4% senior notes (Note 6). The 2010 amount is reduced from the total 12.5 million equivalent shares that would have been issued upon conversion to reflect the weighted average impact of the number of days the debt was outstanding in 2010. Net interest expense on the 4% senior notes totaled $1.6 million in 2011.
g. Amount represents total equivalent common stock shares assuming conversion of 5¼% notes (Note 6). Net interest expense on the 5¼% notes totaled $0.7 million in 2011, $4.4 million in 2010 and $4.0 million in 2009.

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,		
	2011	2010	2009
Outstanding options (in thousands)	6,999	7,696	8,271
Average exercise price	$ 17.29	$ 16.53	$ 15.21

10. 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 "Loss from discontinued operations."

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

	Years Ended December 31, 2011	2010	2009
Accretion and other sulphur reclamation and contingency obligations	$ 9,503	$ 1,415	$ 1,863
Caretaking costs - Port Sulphur	1,556	2,923	2,119
Environmental remediation activities, net of insurance reimbursements [a]	(1,266)	36	2,027
Sulphur retiree costs (credits) [b]	(1,135)	(1,330)	(444)
General and administrative and legal	230	382	324
Insurance	228	213	177
Other	248	(273)	31
Loss from discontinued operations	$ 9,364	$ 3,366	$ 6,097

a. Primarily relates to certain environmental remediation activities at the Port Sulphur, Louisiana and Galveston, Texas facilities.
b. Reflects changes in the postretirement benefit cost obligation associated with certain retired former sulphur employees (Note 15).

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. Cumulative legal fees and related settlement amounts incurred with respect to this indemnification total approximately $1.1 million (since 2002) (Note 15).

Sulphur Reclamation Obligations
McMoRan is currently meeting its financial obligations relating to the future abandonment of its former Main Pass sulphur facilities with the Bureau of Safety and Environmental Enforcement (BSEE) using financial assurances from MOXY. McMoRan and its subsidiaries' ongoing compliance with applicable BSEE requirements will be subject to meeting certain financial and other criteria.

11. EMPLOYEE BENEFITS

Stock-Based Awards. At December 31, 2011, McMoRan had four shareholder-approved stock incentive plans. 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 stock incentive plans.

Plan	Authorized amount of stock-based awards	Shares available for grant at December 31, 2011
2008 Stock Incentive Plan (2008 Plan)	11,500,000	4,630,884
2005 Stock Incentive Plan (2005 Plan)	3,500,000	2,125
2004 Director Compensation Plan (2004 Directors Plan)	175,000	-
2003 Stock Incentive Plan (2003 Plan)	2,000,000	1,000

Restricted Stock Units. Under McMoRan's incentive plans, its Board of Directors granted 30,000 RSUs in 2011, 48,500 RSUs in 2010 and 20,000 RSUs in 2009. 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 21,088 shares in 2011, 18,596 shares in 2010 and 13,861 shares in 2009. Upon issuance of the RSUs, unearned compensation equivalent to the market value at the date of grant 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 $0.4 million of this deferred compensation to expense in 2011, $0.4 million in 2010 and $0.3 million in 2009.

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:

	2011		2010		2009	
	Number of Options	Average Option Price	Number of Options	Average Option Price	Number of Options	Average Option Price
Beginning of year	11,867,750	$13.69	10,446,250	$13.37	9,116,750	$14.91
Granted	1,857,500	17.27	1,821,500	15.57	1,855,500	6.46
Exercised	(98,750)	9.58	(154,500)	13.75	-	-
Expired/forfeited	(361,000)	16.21	(245,500)	14.00	(526,000)	15.83
End of year	13,265,500	14.15	11,867,750	13.69	10,446,250	13.37
Exercisable at end of year	10,040,748		8,920,187		7,549,500	

The total intrinsic value of options exercised during the years ended December 31, 2011 and 2010 was $0.9 million and $2.1 million, respectively. There were no options exercised in the year ended December 31, 2009. The weighted average fair value per share of shares vested during the years ended December 31, 2011, 2010 and 2009 was $11.31, $11.42 and $11.19, respectively. The total intrinsic value of all McMoRan options outstanding at December 31, 2011 was $66.7 million with a weighted average life of 4.7 years. The total intrinsic value of exercisable options totaled $58.3 million at December 31, 2011. The exercisable options had a weighted average life of 4.3 years and a weighted average exercise price of $14.02.

The Co-Chairmen of McMoRan's Board of Directors agreed to forgo all cash compensation during each of the three years ended December 31, 2011. 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 $17.25 per share in February 2011, 400,000 options at an exercise price of $15.73 per share in February 2010 and 400,000 options at an exercise price of $6.44 per share in February 2009. The Co-Chairmen also received additional grants totaling 350,000 stock options in February 2011, February 2010 and January 2009, all of which vest ratably over a four-year period.

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

	Years Ended December 31,		
	2011	2010	2009
Cost of options awarded to employees (including directors) [a]	$ 17,230	$ 17,435	$ 13,152
Cost of options awarded to non-employees	654	870	696
Cost of restricted stock units	441	402	345
Total stock-based compensation cost	$ 18,325	$ 18,707	$ 14,193

a. Includes $4.9 million, $4.7 million and $1.8 million of compensation charges associated with immediately vested stock options granted to certain executive officers (including McMoRan's Co-Chairmen) during 2011, 2010 and 2009, respectively. Also includes $2.3 million, $2.0 million and

$1.1 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 2011, 2010 and 2009, 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, 2011 is as follows (in thousands):

	2011	2010	2009
General and administrative expenses	$ 9,944	$ 9,750	$ 7,162
Exploration expenses	8,266	8,639	6,633
Main Pass Energy Hub costs	115	318	398
Total stock-based compensation cost	$ 18,325	$ 18,707	$ 14,193

As of December 31, 2011, total compensation cost related to nonvested, approved stock option awards not yet recognized in earnings was approximately $14.8 million, which is expected to be recognized over a weighted average period of two years. The fair value of option awards is estimated on the date of grant using a Black-Scholes 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 weighted average fair value of stock options granted and assumptions used to value stock option awards during the years ended December 31, 2011, 2010 and 2009 are noted in the following table:

	2011	2010	2009
Weighted average fair value of stock options granted [a]	$ 10.76	$ 10.04	$ 3.97
Expected and weighted average volatility	62.43 %	66.79 %	64.88 %
Expected life of options (in years) [a]	6.71	6.62	6.43
Risk-free interest rate	2.58 %	3.02 %	1.87 %

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 2011, 2010 and 2009). The expected life and fair value of stock options on the respective grant dates during the years ended December 31, 2011, 2010 and 2009 for such option awards are as follows:

	2011	2010	2009
Expected life (in years)	7.44	7.22	6.77
Fair value of stock option on date of grant	$ 11.05	$ 10.60	$ 4.04

On February 6, 2012, McMoRan's Board of Directors granted a total of 1,953,500 stock options to its employees at an exercise price of $13.00 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 2012. The remaining options granted vest ratably over a four-year period.

Other Benefits. McMoRan 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, 2011, the health care trend rate used for Other Benefits was 7.9 percent in 2011, decreasing ratably annually until reaching 4.5 percent in 2028. For the year ended December 31, 2010, the health care trend rate used for Other Benefits was 7.9 percent in 2010, decreasing ratably annually until reaching 4.5 percent in 2027. 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 Other Benefits plan follows (in thousands):

	Years Ended December 31,	
	2011	2010
Change in benefit obligation:		
Benefit obligation at the beginning of year	$ (4,449)	$ (4,851)
Service cost	(53)	(49)
Interest cost	(191)	(214)
Actuarial gains (losses)	353	289
Participant contributions	(217)	(197)
Benefits paid	402	573
Benefit obligation at end of year	(4,155)	(4,449)
Change in plan assets:		
Fair value of plan assets at beginning of year	-	-
Return on plan assets	-	-
Employer/participant contributions	402	573
Benefits paid	(402)	(573)
Fair value of plan assets at end of year	-	-
Funded status	$ (4,155)	$ (4,449)
Weighted-average assumptions :		
Discount rate	4.2%	5.2%
Expected return on plan assets	-	-
Rate of compensation increase	-	-

Expected benefit payments for McMoRan's Other Benefits plan approximate $0.5 million in each of the two years ending December 31, 2013, $0.4 million in the years ending December 31, 2014 and 2015, $0.3 million in the year ending December 31, 2016 and a total of $1.4 million during the five years thereafter. The components of net periodic benefit cost for McMoRan's plans follow (in thousands):

	Other Benefits		
	2011	2010	2009
Service cost	$ 53	$ 49	$ 52
Interest cost	191	214	271
Return on plan assets	-	-	-
Amortization of prior service costs	(40)	(40)	(40)
Net periodic benefit cost	$ 204	$ 223	$ 283

Included in accumulated other comprehensive loss at December 31, 2011 (Note 13), are prior service costs of $0.1 million and actuarial gains of $0.4 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 2012 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 $1.1 million on December 31, 2011 and $1.5 million on December 31, 2010.

McMoRan's results of operations reflect charges to expense totaling $1.0 million in 2011 and $1.1 million in 2010 and 2009 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 its postretirement benefit costs relating to certain former retired sulphur employees (Note 15).

12. INCOME TAXES

McMoRan has a net deferred tax asset of $459.4 million as of December 31, 2011, resulting from net operating loss carryforwards and other temporary differences related to McMoRan's activities. McMoRan has provided a valuation allowance, including approximately $39.9 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, 2011.

As of December 31, 2011 and 2010, McMoRan had federal tax net operating loss carryforwards (NOLs) of approximately $733.9 million and $603.7 million, respectively, and state tax NOLs of approximately $300.5 million and $278.5 million, respectively. These NOLs are scheduled to expire in varying amounts between tax years 2013 through 2031.

Federal tax regulations impose certain annual limitations on the utilization of NOLs 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 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. McMoRan determined that such a change of ownership occurred during 2010, which, depending upon the amounts and timing of future taxable income generated, may limit McMoRan's ability to use its existing NOLs to fully offset taxable income in individual 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 2007. NOL amounts prior to this time are also subject to audit.

The components of McMoRan's deferred tax assets (liabilities) at December 31, 2011 and 2010 follow (in thousands):

	December 31,	
	2011	2010
Federal and state net operating loss carryforwards	$ 271,073	$ 222,308
Property, plant and equipment	21,150	55,839
Reclamation and shutdown reserves	120,449	134,362
Deferred compensation, postretirement and pension benefits and accrued liabilities	44,311	35,437
Other, net	2,403	4,976
Less: valuation allowance	(459,386)	(452,922)
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):

	Years Ended December 31,		
	2011	2010	2009
Income tax benefit computed at the federal statutory income tax rate	$ 5,588	$ 42,119	$ 74,701
Change in valuation allowance	(7,357)	(43,098)	(71,922)
State NOLs (not impacting federal tax)	1,870	1,083	1,792
Other	(101)	(104)	(2,126)
Federal income tax benefit (provision)	-	-	2,445
State income tax benefit (provision)	-	-	-
Total income tax benefit (provision)	$ -	$ -	$ 2,445

13. COMPREHENSIVE LOSS

The components of McMoRan's comprehensive loss for 2011, 2010 and 2009 follow (in thousands):

	Years Ended December 31,		
	2011	2010	2009
Net loss	$ (15,968)	$ (120,342)	$ (210,986)
Other comprehensive loss			
Amortization of previously unrecognized pension components, net	(40)	(40)	(40)
Change in unrecognized net gains (losses) of pension plans	353	289	(284)
Comprehensive loss	$ (15,655)	$ (120,093)	$ (211,310)

14. TRANSACTIONS WITH AFFILIATES

FM Services Company, a wholly owned subsidiary of FCX and a company with 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, Louisiana corporate headquarters, totaled $7.9 million in 2011, $7.7 million in 2010 and $8.4 million in 2009. 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, 2011 and 2010, respectively, McMoRan had an obligation to fund $2.9 million and $2.8 million of FM Services costs, primarily reflecting long-term employee pension and postretirement medical obligations (Notes 5 and 11).

On December 30, 2010, FCX purchased 500,000 shares of McMoRan's 5.75% preferred stock (Note 8).

15. COMMITMENTS AND CONTINGENCIES

Commitments. McMoRan has $268.5 million of estimated 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 $36.0 million of expenditures for drilling rig contract charges anticipated 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, and office space in Lafayette, Louisiana, which expires in November 2012. At December 31, 2011, McMoRan's total minimum annual contractual charges aggregated $5.8 million, with payments totaling $2.4 million in 2012, $2.2 million in 2013 and $1.2 million in 2014. Rent expense, including rent allocated to McMoRan by FM Services (Note 14), totaled $3.0 million in 2011, $3.0 million in 2010 and $3.2 million in 2009.

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 $1.5 million at December 31, 2011 and $3.0 million at December 31, 2010, including $0.7 million and $0.2 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 2011 used an initial health care cost trend rate of 7.9 percent in 2011 decreasing ratably to 4.5 percent in 2028. During 2010, the assessment used an initial health care cost trend rate of 7.9 percent in 2010 decreasing ratably to 4.5 percent in 2027. McMoRan applied a discount rate of 8.5 percent at December 31, 2011 and 2010 to the consultant's future cost estimates. McMoRan reduced the liability by $1.6 million and $2.2 million at December 31, 2011 and 2010, respectively, primarily reflecting decreases in future health claim costs resulting from lower than expected actual health claim reimbursements partially 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. Cumulative legal fees and related settlement amounts incurred with respect to historical oil and gas liabilities McMoRan assumed from IMC Global total approximately $1.1 million (since 2002). No additional amounts have been recorded because no specific liability has been identified and assessed to be probable of requiring McMoRan to fund any future material amounts.

Since 2007 and through 2011 McMoRan has funded over $360 million of reclamation costs to settle a significant portion of the asset retirement obligations assumed in an oil and gas property acquisition in 2007, including certain properties damaged in the 2008 hurricanes. Of this amount, approximately $277 million has been incurred during the last two years as a result of McMoRan's efforts to reduce its exposure to future weather-related events and to remove idle structures in accordance with regulatory requirements. McMoRan intends to spend approximately $60 million on additional reclamation activities in 2012 to settle the asset retirement obligations of certain of its maturing properties. McMoRan's estimates of existing asset retirement obligations involve inherent uncertainties and are subject to change over time as a result of several factors, including, without limitation, changes in the industry's regulatory environment, changes in the cost and availability of required equipment and expertise to complete the work, changes in timing, and changes in scope that are identified as reclamation projects progress. McMoRan revises its reclamation estimates, as appropriate, when such changes in estimates become known.

The results from these reclamation activities as well as information obtained from other industry sources indicate that the cost to conduct reclamation projects in the offshore Gulf of Mexico region has risen, particularly since the occurrence of the 2010 *Deepwater Horizon* incident. As a result, McMoRan re-assessed the estimates of substantially all of its oil and gas property asset retirement obligations in 2011. As a result of this assessment McMoRan revised its estimates related to certain recently completed, ongoing and/or near term reclamation projects resulting in an increase to accretion expense of approximately $57.3 million. Approximately $19.8 million of these charges were reimbursed to McMoRan under its insurance policies related to damage restoration costs resulting from the 2008 hurricane events. In addition, McMoRan also revised its estimates related to certain longer term producing properties resulting in adjustments that increased property, plant and equipment by approximately $54.6 million.

Revisions made for certain properties depending upon the respective circumstances include consideration of the following: (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 McMoRan's 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) when applicable, changes in McMoRan's credit-adjusted, risk-free interest rate. McMoRan's credit adjusted, risk-free interest rates ranged from 4.1 percent to 6.4 percent at December 31, 2011, 4.6 percent to 9.9 percent at December 31, 2010 and 6.9 percent to 13.1 percent at December 31, 2009. At December 31, 2011, McMoRan's estimated undiscounted reclamation obligations, including inflation and market risk premiums, totaled $461.0 million, including $41.0 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,		
	2011	2010	2009
Oil and Natural Gas			
Asset retirement obligations at beginning of year	$ 358,624	$ 428,711	$ 421,201
Liabilities settled	(153,357)	(124,142)	(42,212)
Scheduled accretion expense [a]	14,192	17,095	30,910
Reclamation costs assumed	-	2,268	2,711
Properties sold	-	(411)	-
Liabilities recorded in 2010 property acquisition	-	9,882	-
Revision for changes in estimates – charged to operations [a]	57,304	9,041	157
Revision for changes in estimates – adjustments to property, plant and equipment, net	54,604	16,180	15,944
Other, net	(4,973)	-	-
Asset retirement obligations at end of year	$ 326,394	$ 358,624	$ 428,711
Sulphur			
Asset retirement obligations at beginning of year	$ 25,266	$ 27,452	$ 23,003
Liabilities settled	(13,425)	(3,601)	(481)
Scheduled accretion expense [b]	1,542	1,415	2,001
Revision for changes in estimates [b]	4,362	-	2,929
Asset retirement obligations at end of year	$ 17,745	$ 25,266	$ 27,452

a. Accretion expense and other charges to operations are included within depletion, depreciation and amortization expense in the accompanying consolidated statements of operations.
b. Included within loss from discontinued operations.

At December 31, 2011, McMoRan had $7.6 million in restricted investments associated with third party prepayments of their share of future abandonment costs and $51.4 million held in escrow associated with the surety funding requirements in favor of a third party related to a portion of the reclamation obligations assumed in a 2007 oil and gas property acquisition. McMoRan is required to make quarterly installment payments under these requirements totaling $15 million annually through July 2010 and $5.0 million a year 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.

16. MAIN PASS ENERGY HUB™ PROJECT

McMoRan'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. McMoRan refers to this project as the Main Pass Energy Hub™ (MPEH™) project.

McMoRan obtained a license covering the potential use of the facility for the import of liquefied natural gas (LNG) in early 2007; this license expired in 2012. Commercialization of the project was adversely affected by increased domestic supplies of natural gas, excess LNG regasification capacity and general market conditions. McMoRan continues to evaluate other potential commercial options including the use of the MPEH™ assets for handling and storage of various hydrocarbon commodities. 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. McMoRan incurred costs for the MPEH™ project totaling $0.6 million in 2011, $1.0 million in 2010 and $1.6 million in 2009.

Currently, McMoRan, through its subsidiary, 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 McMoRan's equity interest in the project. Future financing and commercial arrangements could also reduce McMoRan's equity interest in the project.

17. SUPPLEMENTARY OIL AND GAS INFORMATION

McMoRan's oil and gas exploration, development and production activities are primarily 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,	
	2011	2010
	(In Thousands)	
Unproved properties	$ 1,575,806	$ 1,054,399
Proved properties	2,548,305	2,436,987
Subtotal	4,124,111	3,491,386
Less accumulated depreciation and amortization	(1,942,215)	(1,705,810)
Net oil and gas properties	$ 2,181,896	$ 1,785,576

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

	Years Ended December 31,		
	2011	2010	2009
	(In Thousands)		
Acquisition of properties:			
Proved	$ -	$ 191,605	$ 78
Unproved	49,123	819,001	-
Exploration costs	556,337	207,806	148,465
Development costs	54,399	53,465	16,715
	$ 659,859	$ 1,271,877	$ 165,258

The following table reflects the net changes in McMoRan's capitalized exploratory well costs during each of the three years in the period ended December 31, 2011 (in thousands):

	Years Ended December 31,		
	2011	2010	2009
Beginning of year	$ 218,524	$ 62,649	$ 43,791
Additions to capitalized exploratory well costs pending determination of proved reserves	504,142	163,563	85,356
Reclassifications to wells, facilities, and equipment based on determination of proved reserves	-	-	(6,180)
Amounts charged to expense	(33,005)	(7,688)	(60,318)
End of year	$ 689,661	$ 218,524	$ 62,649

As of December 31, 2011, McMoRan had two wells (the Davy Jones initial discovery well and Blackbeard West No. 1) with costs that had been capitalized for a period in excess of one year following the completion of the initial exploratory drilling operations. Significant activities are ongoing for the further assessment and development of the Davy Jones discovery well, with equipment procurement and other well test preparation activities currently in progress with completion expected in the first quarter 2012. McMoRan's total investment in the Davy Jones complex, which includes $474.8 million in allocated property acquisition costs, totaled $774.8 million at December 31, 2011.

The Blackbeard West No. 1 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 requiring further evaluation. The well has been temporarily abandoned while McMoRan evaluates whether to drill deeper or complete the well to test the existing zones. McMoRan's investment in the Blackbeard West No. 1 drilling costs approximated $31.3 million at December 31, 2011. In the fourth quarter 2011, McMoRan commenced the drilling of a new well within the Blackbeard West unit (Blackbeard West No. 2 well) on Ship Shoal Block 188 to evaluate the Miocene age sands seen in the Blackbeard East prospect above 25,000 feet. The drilling of this ultra-deep well, which has a proposed total depth of 26,000 feet allows McMoRan to maintain its rights to the 25,000 gross acres within the Blackbeard West unit. McMoRan's investment in the Blackbeard West No. 2 well totaled $10.9 million at December 31, 2011. In addition, McMoRan has approximately $27.6 million of allocated leasehold costs for the Blackbeard West unit resulting from the PXP Acquisition.

Proved Oil and Natural Gas Reserves (Unaudited). Proved oil and natural gas reserves for the periods ending December 31, 2011, 2010 and 2009 have been estimated by Ryder Scott Company, L.P. (Ryder Scott), in accordance with the guidelines established by the SEC as set forth in Rule 4-10 (a) (6), (22), (26) and (31) effective December 31, 2009. 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 natural gas liquids (NGLs), are stated in thousands of barrels (MBbls) and natural gas in millions of cubic feet (MMcf).

	Oil and NGLs			Natural Gas		
	2011	2010	2009	2011	2010	2009
Proved reserves:						
Beginning of year	14,557	15,519	16,989	192,495	178,822	242,897
Revisions of previous estimates	6,587	629	1,369	2,622	11,211	(12,610)
Discoveries and extensions	16	-	131	1,934	-	4,377
Production	(3,871)	(2,481)	(2,970)	(45,000)	(43,976)	(55,842)
Sales of reserves	-	(222)	-	-	(140)	-
Purchase of reserves	-	1,112 [a]	-	-	46,578 [a]	-
End of year	17,289 [c]	14,557	15,519	152,051 [b]	192,495	178,822
Proved developed reserves:						
Beginning of year	13,317	13,483	15,039	144,982	135,150	198,610
End of year	15,573 [d]	13,317	13,483	123,626 [b]	144,982	135,150

a. Reflects the estimated proved reserves associated with the 2010 oil and gas property acquisition (Note 2).
b. At December 31, 2011, McMoRan had natural gas imbalances of 0.7 Bcfe for under deliveries and 0.7 Bcfe for over deliveries which are not reflected in the above reserve quantities.
c. Includes 2,848 MBbls of NGLs, approximately 6.7% of total proved reserves on an Mcf equivalent basis.
d. Includes 2,220 MBbls of NGLs, approximately 6.1% of total proved developed reserves on an Mcf equivalent basis.

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. SEC regulations require the use of average prices during the 12-month period prior to the reporting date. The weighted average of these prices for all properties with proved reserves was $100.68 per barrel of oil, $56.82 per barrel of NGLs and $4.29 per Mcf of natural gas at December 31, 2011 and was $76.97 per barrel of oil and $4.70 per Mcf of natural gas at December 31, 2010.

	December 31,	
	2011	2010
	(In Thousands)	
Future cash inflows	$ 2,268,446	$ 2,024,752
Future costs applicable to future cash flows:		
Production costs	(566,947)	(511,235)
Development and abandonment costs	(534,703)	(595,335)
Future income taxes	-	-
Future net cash flows	1,166,796	918,182
Discount for estimated timing of net cash flows (10% discount rate) [a]	(337,965)	(267,262)
	$ 828,831	$ 650,920

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,		
	2011	2010	2009
	(In Thousands)		
Beginning of year	$ 650,920	$ 348,381	$ 705,291
Revisions:			
Accretion of discount	65,092	34,838	70,529
Changes in prices	147,195	196,927	(183,301)
Change in reserve quantities	195,033	53,306	15,459
Other changes, including revised estimates of development costs and changes in timing and other	(107,785)	(71,337)	(97,269)
Discoveries and extensions, less related costs	5,951	-	2,691
Development costs incurred during the year	207,756	175,340	65,256
Change in future income taxes	-	1,476	(324)
Revenues, less production costs	(335,331)	(235,541)	(229,951)
Purchases reserves in place	-	154,967	-
Sales of reserves in place	-	(7,437)	-
End of year	$ 828,831	$ 650,920	$ 348,381

18. 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, 2011 and 2010 and the related condensed consolidating statements of operations and cash flow for the years ended December 31, 2011, 2010 and 2009, which should be read in conjunction with the notes to these consolidated financial statements:

CONDENSED CONSOLIDATING BALANCE SHEET
December 31, 2011

	Parent	MOXY	Freeport Energy	Eliminations	Consolidated McMoRan
			(In Thousands)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ 16,341	$ 552,365	$ 57	$ -	$ 568,763
Accounts receivable	1,850	70,235	-	-	72,085
Inventories	-	36,274	-	-	36,274
Prepaid expenses	668	8,435	-	-	9,103
Current assets from discontinued operations	-	-	682	-	682
Total current assets	18,859	667,309	739	-	686,907
Property, plant and equipment, net	-	2,181,896	30	-	2,181,926
Investment in subsidiaries	1,596,092	-	-	(1,596,092)	-
Amounts due from affiliates	677,127	-	-	(677,127)	-
Restricted cash and other assets	4,641	65,301	-	-	69,942
Long-term assets from discontinued operations	-	-	439	-	439
Total assets	$ 2,296,719	$ 2,914,506	$ 1,208	$ (2,273,219)	$ 2,939,214
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)					
Current liabilities:					
Accounts payable	$ 217	$ 115,121	$ 494	$ -	$ 115,832
Accrued liabilities	787	160,309	-	(274)	160,822
Current portion of debt	66,223	-	-	-	66,223
Current portion of oil and gas accrued reclamation costs	-	58,810	-	-	58,810
Other current liabilities	13,694	754	-	-	14,448
Current liabilities from discontinued operations	-	-	4,990	274	5,264
Total current liabilities	80,921	334,994	5,484	-	421,399
Long-term debt	487,363	-	-	-	487,363
Amounts due to affiliates	-	674,613	2,515	(677,128)	-
Accrued oil and gas reclamation costs	-	267,584	-	-	267,584
Other long-term liabilities	5,471	13,799	1,616	-	20,886
Long-term liabilities from discontinued operations	-	-	19,018	-	19,018
Total liabilities	573,755	1,290,990	28,633	(677,128)	1,216,250
Stockholders' equity (deficit)	1,722,964	1,623,516	(27,425)	(1,596,091)	1,722,964
Total liabilities and stockholders' equity (deficit)	$ 2,296,719	$ 2,914,506	$ 1,208	$ (2,273,219)	$ 2,939,214

CONDENSED CONSOLIDATING BALANCE SHEET
December 31, 2010

	Parent	MOXY	Freeport Energy	Eliminations	Consolidated McMoRan
			(In Thousands)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ 420	$ 904,889	$ 375	$ -	$ 905,684
Accounts receivable	66	86,450	-	-	86,516
Inventories	-	38,461	-	-	38,461
Prepaid expenses	657	14,821	-	-	15,478
Current assets from discontinued operations	-	-	702	-	702
Total current assets	1,143	1,044,621	1,077	-	1,046,841
Property, plant and equipment, net	-	1,785,576	31	-	1,785,607
Investment in subsidiaries	1,525,531	-	-	(1,525,531)	-
Amounts due from affiliates	772,502		-	(772,502)	-
Restricted cash and other assets	6,536	57,391	-	-	63,927
Long-term assets from discontinued operations	-	-	2,989	-	2,989
Total assets	$ 2,305,712	$ 2,887,588	$ 4,097	$ (2,298,033)	$ 2,899,364
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)					
Current liabilities:					
Accounts payable	$ 444	$ 100,163	$ 2,051	$ -	$ 102,658
Accrued liabilities	8,899	90,784	-	(320)	99,363
Current portion of debt	74,720	-	-	-	74,720
Current portion of oil and gas accrued reclamation costs	-	120,970	-	-	120,970
Other current liabilities	5,950	818	-	-	6,768
Current liabilities from discontinued operations	-	-	13,445	320	13,765
Total current liabilities	90,013	312,735	15,496	-	418,244
Long-term debt	485,256	-	-	-	485,256
Amounts due to affiliates	-	770,373	2,129	(772,502)	-
Accrued oil and gas reclamation costs	-	237,654	-	-	237,654
Other long-term liabilities	6,106	8,876	1,614	-	16,596
Long-term liabilities from discontinued operations	-	-	17,277	-	17,277
Total liabilities	581,375	1,329,638	36,516	(772,502)	1,175,027
Stockholders' equity (deficit)	1,724,337	1,557,950	(32,419)	(1,525,531)	1,724,337
Total liabilities and stockholders' equity (deficit)	$ 2,305,712	$ 2,887,588	$ 4,097	$ (2,298,033)	$ 2,899,364

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
Year Ended December 31, 2011

	Parent	MOXY	Freeport Energy	Eliminations	Consolidated McMoRan
			(In Thousands)		
Revenues:					
Oil and natural gas	$ -	$ 542,310	$ -	$ -	$ 542,310
Service	-	13,104	39	(39)	13,104
Total revenues	-	555,414	39	(39)	555,414
Costs and expenses:					
Production and delivery costs	-	206,358	-	(39)	206,319
Depletion, depreciation and amortization expense	-	307,902	-	-	307,902
Exploration expenses	-	81,742	-	-	81,742
General and administrative expenses	9,291	40,180	-	-	49,471
Main Pass Energy Hub™ costs	-	-	588	-	588
Insurance recoveries	-	(91,076)	-	-	(91,076)
Gain on sale of oil and gas property	-	(900)	-	-	(900)
Total costs and expenses	9,291	544,206	588	(39)	554,046
Operating loss	(9,291)	11,208	(549)	-	1,368
Interest expense, net	(8,782)	-	-	-	(8,782)
Equity in losses of consolidated subsidiaries	2,127	-	-	(2,127)	-
Other income (expense), net	(22)	832	-	-	810
Loss from continuing operations before income taxes	(15,968)	12,040	(549)	(2,127)	(6,604)
Income tax expense	-	-	-	-	-
Loss from continuing operations	(15,968)	12,040	(549)	(2,127)	(6,604)
Loss from discontinued operations	-	-	(9,364)	-	(9,364)
Net loss	(15,968)	12,040	(9,913)	(2,127)	(15,968)
Preferred dividends and other related preferred stock costs	(42,800)	-	-	-	(42,800)
Net loss applicable to common stock	$ (58,768)	$ 12,040	$ (9,913)	$ (2,127)	$ (58,768)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
Year Ended December 31, 2010

	Parent	MOXY	Freeport Energy	Eliminations	Consolidated McMoRan
			(In Thousands)		
Revenues:					
Oil and natural gas	$ -	$ 418,816	$ -	$ -	$ 418,816
Service	-	15,560	53	(53)	15,560
Total revenues	-	434,376	53	(53)	434,376
Costs and expenses:					
Production and delivery costs	-	182,843	-	(53)	182,790
Depletion, depreciation and amortization expense	-	282,062	-	-	282,062
Exploration expenses	-	42,608	-	-	42,608
Gain on oil and gas derivative contracts	-	(4,240)	-	-	(4,240)
General and administrative expenses	13,931	37,598	-	-	51,529
Main Pass Energy Hub™ costs	-	-	1,011	-	1,011
Gain on sale of oil and gas property	-	(3,455)	-	-	(3,455)
Insurance recoveries	-	(38,944)	-	-	(38,944)
Total costs and expenses	13,931	498,472	1,011	(53)	513,361
Operating loss	(13,931)	(64,096)	(958)	-	(78,985)
Interest expense, net	(38,196)	(20)	-	-	(38,216)
Equity in losses of consolidated subsidiaries	(68,201)	-	-	68,201	-
Other income (expense), net	(14)	239	-	-	225
Loss from continuing operations before income taxes	(120,342)	(63,877)	(958)	68,201	(116,976)
Income tax expense	-	-	-	-	-
Loss from continuing operations	(120,342)	(63,877)	(958)	68,201	(116,976)
Loss from discontinued operations	-	-	(3,366)	-	(3,366)
Net loss	(120,342)	(63,877)	(4,324)	68,201	(120,342)
Preferred dividends and other related preferred stock costs	(77,101)	-	-	-	(77,101)
Net loss applicable to common stock	$ (197,443)	$ (63,877)	$ (4,324)	$ 68,201	$ (197,443)

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	56	(56)	12,459
Total revenues	-	435,435	56	(56)	435,435
Costs and expenses:					
Production and delivery costs	-	193,081	-	(56)	193,025
Depletion, depreciation and amortization expense	-	313,980	-	-	313,980
Exploration expenses	-	94,281	-	-	94,281
Gain on oil and gas derivative contracts	-	(17,394)	-	-	(17,394)
General and administrative expenses	5,749	37,181	24	-	42,954
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	(56)	603,869
Operating loss	(5,749)	(161,102)	(1,583)	-	(168,434)
Interest expense, net	(41,152)	(1,791)	-	-	(42,943)
Equity in 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 other related preferred stock 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 CASH FLOW
Year Ended December 31, 2011

	Parent	MOXY	Freeport Energy	Consolidated McMoRan
	(In Thousands)			
Cash flow from operating activities:				
Net cash provided by (used in) continuing operations	$ (20,592)	$ 263,095	$ (473)	$ 242,030
Net cash used in discontinued operations	-	-	(14,982)	(14,982)
Net cash provided by (used in) operating activities	(20,592)	263,095	(15,455)	227,048
Cash flow from investing activities:				
Exploration, development and other capital expenditures	-	(509,494)	-	(509,494)
Acquisition of oil and gas properties	-	(9,520)	-	(9,520)
Proceeds from sale of oil and gas property	-	900	-	900
Net cash used in investing activities	-	(518,114)	-	(518,114)
Cash flow from financing activities:				
Dividends paid and conversion inducement payments on convertible preferred stock	(37,951)	-	-	(37,951)
Credit facility refinancing	-	(1,745)	-	(1,745)
Payment of 5¼% convertible senior notes	(6,543)	-	-	(6,543)
Proceeds from exercise of stock options	946	-	-	946
Debt and equity issuance costs	(562)	-	-	(562)
Investment from parent	(14,750)	-	14,750	-
Amounts payable to consolidated affiliate	95,373	(95,760)	387	-
Net cash (used in) provided by financing activities	36,513	(97,505)	15,137	(45,855)
Net increase (decrease) in cash and cash equivalents	15,921	(352,524)	(318)	(336,921)
Cash and cash equivalents at beginning of year	420	904,889	375	905,684
Cash and cash equivalents at end of period	$ 16,341	$ 552,365	$ 57	$ 568,763

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOW
Year Ended December 31, 2010

	Parent	MOXY	Freeport Energy	Consolidated McMoRan
	(In Thousands)			
Cash flow from operating activities:				
Net cash provided by (used in) continuing operations	$ (860,748)	$ 963,955	$ (2,760)	$ 100,447
Net cash used in discontinued operations	-	-	(2,217)	(2,217)
Net cash provided by (used in) operating activities	(860,748)	963,955	(4,977)	98,230
Cash flow from investing activities:				
Exploration, development and other capital expenditures	-	(217,252)	-	(217,252)
Acquisition of properties, net	-	(86,134)	-	(86,134)
Proceeds from sale of oil and gas property	-	2,920	-	2,920
Net cash used in investing activities	-	(300,466)	-	(300,466)
Cash flow from financing activities:				
Proceeds from sale of preferred stock	700,000	-	-	700,000
Proceeds from sale of senior notes	200,000	-	-	200,000
Dividend and inducement payments on convertible preferred stock	(27,306)	-	-	(27,306)
Costs associated with sale of preferred stock and senior notes	(6,689)	-	-	(6,689)
Proceeds from exercise of stock options	497	-	-	497
Investment from parent	(5,350)	-	5,350	-
Net cash provided by financing activities	861,152	-	5,350	866,502
Net increase (decrease) in cash and cash equivalents	404	663,489	373	664,266
Cash and cash equivalents at beginning of year	16	241,400	2	241,418
Cash and cash equivalents at end of year	$ 420	$ 904,889	$ 375	$ 905,684

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 (used in) 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
Dividend and inducement 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

19. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	Revenues	Operating Income (Loss)	Net Income (Loss) [a]	Net Income (Loss) per Share Basic	Net Income (Loss) per Share Diluted
	(In Thousands, Except Per Share Amounts)				
2011					
1st Quarter	$ 137,004	$ (9,265)	$ (27,550)	$ (0.17)	$ (0.17)
2nd Quarter	158,308	(35,392)	(50,198)	(0.32)	(0.32)
3rd Quarter	138,183	2,836	(9,420)	(0.06)	(0.06)
4th Quarter	121,919	43,189	28,400	0.18	0.16
	$ 555,414	$ 1,368	$ (58,768)		

	Revenues	Operating Loss	Net Loss [a]	Net Loss per Share Basic	Net Loss per Share Diluted
	(In Thousands, Except Per Share Amounts)				
2010					
1st Quarter	$ 132,488	$ (41,282)	$ (66,160)	$ (0.74)	$ (0.74)
2nd Quarter	108,041	(5,188)	(21,746)	(0.23)	(0.23)
3rd Quarter	94,840	(10,927)	(25,253)	(0.26)	(0.26)
4th Quarter	99,007	(21,588)	(84,284)	(0.83)	(0.83)
	$ 434,376	$ (78,985)	$ (197,443)		

a. Represents net income (loss) attributable to common shareholders, which includes preferred dividends and inducement payments for early conversion of preferred stock 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 quarter ended December 31, 2011 that has materially affected, or is reasonably likely to materially affect our internal control over financial reporting.

Item 9B. Other Information

Not Applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by Item 10 regarding our executive officers appears in a separately captioned heading after Item 4. in Part I of this report on Form 10-K. The information set forth under the headings "Information About Director Nominees" and "Section 16(a) Beneficial Ownership Reporting Compliance" of our definitive proxy statement to be filed with the Securities and Exchange Commission (SEC) pursuant to Regulation 14A, relating to our 2012 annual meeting of stockholders is incorporated herein by reference.

Item 11. Executive Compensation

The information set forth under the headings "Director Compensation" and "Executive Officer Compensation" of our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A, relating to our 2012 annual meeting of stockholders is incorporated herein by reference.

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

The information set forth under the headings "Stock Ownership of Directors and Executive Officers" and "Stock Ownership of Certain Beneficial Owners" of our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A, relating to our 2012 annual meeting of stockholders is incorporated herein by reference.

Securities Authorized for Issuance Under Equity Compensation Plans.

The following table provides information as of December 31, 2011, with respect to compensation plans under which our equity securities are authorized for issuance.

	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights	Weighted Average Exercise Price of Outstanding Options	Number of Securities Remaining Available for Future Grant Under Equity Compensation Plans
Equity compensation plans approved by stockholders	$ 13,370,748 [a]	$ 14.15 [a]	$ 4,634,009 [b]
Equity compensation plans not approved by stockholders	-	-	-

a. Includes shares issuable upon the vesting of 80,248 restricted stock units, and the termination of deferrals with respect to 25,000 restricted stock units that were vested as of December 31, 2011. These awards are not reflected in the "weighted average exercise price of outstanding options" as they do not have an exercise price.

b. As of December 31, 2011, there were 4,630,884 shares remaining available for future issuance under the 2008 Stock Incentive Plan, all of which could be issued under the terms of the plan pursuant to awards of options and stock appreciation rights, and 3,381,500 of which could be issued under the terms of the plan pursuant to awards of restricted stock, restricted stock units and "other stock-based" awards. In addition, there were 2,125 shares remaining available for future issuance under the 2005 Stock Incentive Plan, all of which could be issued under the terms of the plan pursuant to awards of options, stock appreciation rights, restricted stock, restricted stock units and "other stock-based" awards. There were also 1,000 shares remaining available for future issuance under each of the 2003 Stock Incentive Plan, all of which could be issued under the respective terms of the plans pursuant to awards of options, stock appreciation rights, limited rights, restricted stock and "other stock-based" awards.

See Note 11 to our consolidated financial statements for further information regarding the significant features of the above plans.

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

The information set forth under the heading "Certain Transactions" of our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A, relating to our 2012 annual meeting of stockholders is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services

The information set forth under the heading "Independent Registered Public Accounting Firm" of our definitive proxy statement to be filed pursuant to Regulation 14A, relating to our 2012 annual meeting of stockholders 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 data. 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 BOEM (defined below) or a similar depiction on official protraction or similar diagrams issued by a state bordering on the Gulf of Mexico.

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

BOEM. The Bureau of Ocean Energy Management (an agency of the Department of the Interior; formed upon dissolution of the Bureau of Ocean Energy Management, Regulation and Enforcement October 1, 2011, and responsible for pre-leasing environmental and leasing matters).

BSEE. The Bureau Safety and Environmental Enforcement (an agency of the Department of the Interior; formed upon dissolution of the Bureau of Ocean Energy Management, Regulation and Enforcement October 1, 2011, and responsible for environmental matters related to operations, safety and operational matters generally).

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 temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

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

Delineation drilling. Drilling a well 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.

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.

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

Natural gas liquids (NGLs). 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.

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.

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, and 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 reasonably 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.

True Vertical Depth (TVD). The vertical distance from the surface to the current drilling depth.

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 February 29, 2012.

McMoRan Exploration Co.

By: /s/ James R. Moffett
James R. Moffett
Co-Chairman of the Board,
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and the capacities indicated, on February 29, 2012.

/s/ James R. Moffett James R. Moffett	Co-Chairman of the Board, President and Chief Executive Officer
/s/ Richard C. Adkerson Richard C. Adkerson	Co-Chairman of the Board
* B.M. Rankin, Jr.	Vice Chairman of the Board
/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)
* A. Peyton Bush, III	Director
* William P. Carmichael	Director
* Robert A. Day	Director
* James C. Flores	Director
* Gerald J. Ford	Director
* H. Devon Graham, Jr.	Director
* Suzanne T. Mestayer	Director
* John F. Wombwell	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 Mergers dated August 1, 1998, by and among McMoRan, McMoRan Oil and Gas Co., Freeport-McMoRan Sulphur Inc. MOXY LLC and Brimstone LLC		S-4	333-61171	10/06/1998
2.2	Agreement and Plan of Merger dated September 19, 2010, by and among McMoRan, McMoRan Oil & Gas LLC, McMoRan GOM, LLC and McMoRan Offshore LLC, and Plains Exploration & Production Company, PXP Gulf Properties LLC and PXP Offshore LLC		10-Q	001-07791	11/09/2010
3.1	Composite Certificate of Incorporation of McMoRan	X			
3.2	Amended and Restated By-Laws of McMoRan as amended effective through February 1, 2010		8-K	001-07791	02/03/2010
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, 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	First Supplemental Indenture dated as of November 14, 2007, by and between McMoRan and the Bank of New York, as trustee (related to the 11.875% Senior Notes due 2014)		8-K	001-07791	11/15/2007
4.6	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
4.7	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
4.8	Registration Rights Agreement dated December 30, 2010, by and among McMoRan and Plains Exploration & Production Company		8-K	001-07791	01/04/2011
4.9	Registration Rights Agreement (related to the 4% Convertible Senior Notes) dated December 30, 2010 by and among McMoRan and investors		8-K	001-07791	01/04/2011

Exhibit Number	Exhibit Title	Filed with this Form 10-K	Incorporated by Reference Form	File No.	Date Filed
4.10	Registration Rights Agreement (related to the 5.75% Convertible Perpetual Preferred Stock, Series 1) dated December 30, 2010 by and among McMoRan and investors		8-K	001-07791	01/04/2011
4.11	Registration Rights Agreement dated December 30, 2010 by and among McMoRan and Freeport-McMoRan Preferred LLC		8-K	001-07791	01/04/2011
4.12	Registration Rights Agreement dated September 8, 2011 by and among McMoRan Exploration Co. and Whitney Exploration, LLC		8-K	001-07791	09/09/2011
4.13	Indenture dated December 30, 2010 by and among McMoRan and U.S. Bank National Association, as trustee		8-K	001-07791	01/04/2011
4.14	Indenture dated October 6, 2011 by and among McMoRan Exploration Co. and The Bank of New York Mellon Trust Company, N. A., as Trustee		8-K	001-07791	10/11/2011
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 Phosphate Company, Phosphate Resource Partners Limited Partnership, IMC Phosphates MP Inc., MOXY and McMoRan		10-Q	001-07791	08/14/2002
10.3	Amended and Restated Services Agreement dated as of January 1, 2002 between McMoRan and FM Services Company		10-Q	001-07791	08/14/2003
10.4	Letter Agreement dated August 22, 2000 between Devon Energy Corporation and Freeport Sulphur		10-Q	001-07791	10/25/2000
10.5	Asset Purchase Agreement dated effective December 1, 1999 between SOI Finance Inc., Shell Offshore Inc. and MOXY		10-K	001-07791	02/08/2000
10.6	Employee Benefits Agreement by and between Freeport-McMoRan Inc. and Freeport Sulphur		10-K	001-07791	04/16/2002
10.7	Purchase and Sales Agreement dated January 25, 2002 but effective January 1, 2002 by and between MOXY and Halliburton Energy Services, Inc		8-K	001-07791	03/11/2002
10.8	Purchase and Sale Agreement dated as of March 29, 2002 by and among Freeport Sulphur, McMoRan, MOXY and Gulf Sulphur Services Ltd., LLP		10-Q	001-07791	05/10/2002
10.9	Purchase and Sale Agreement dated May 9, 2002 by and between MOXY and El Paso Production Company..		10-Q	001-07791	08/14/2002
10.10	Amendment to Purchase and Sale Agreement dated May 22, 2002 by and between MOXY and El Paso Production Company		10-Q	001-07791	08/14/2002
10.11	Master Agreement dated October 22, 2002 by and among Freeport-McMoRan Sulphur LLC, K-Mc Venture LLC, K1 USA Energy Production Corporation and McMoRan		10-K	001-07791	03/27/2003

Exhibit Number	Exhibit Title	Filed with this Form 10-K	Incorporated by Reference Form	File No.	Date Filed
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	Credit Agreement among McMoRan Exploration Co., as parent, McMoRan Oil & Gas LLC, as borrower, JPMorgan Chase Bank, N.A., as administrative agent, Toronto Dominion (New York) LLC, as syndication agent, BNP Paribas, as documentation agent and the lenders party thereto, dated as of June 30, 2011		8-K	001-07791	07/06/2011
10.14	Underwriting Agreement dated June 16, 2009 between McMoRan and J.P. Morgan Securities Inc., as representative of the several underwriters named in Schedule 1 thereto		8-K	001-07791	06/19/2009
10.15	Underwriting Agreement dated June 16, 2009 between McMoRan and J.P. Morgan Securities Inc., as representative of the several underwriters named in Schedule 1 thereto		8-K	001-07791	06/19/2009
10.16	Stock Purchase Agreement dated September 19, 2010 by and among McMoRan, Freeport-McMoRan Preferred LLC and Freeport-McMoRan Copper & Gold Inc.		10-Q	001-07791	11/09/2010
10.17	Stockholder Agreement dated December 30, 2010, by and among McMoRan and Plains Exploration & Production Company		8-K	001-07791	01/04/2011
10.18	Stockholder Agreement dated December 30, 2010, by and among McMoRan, Freeport-McMoRan Copper & Gold Inc. and Freeport-McMoRan Preferred LLC		8-K	001-07791	01/04/2011
10.19	Form of 4% Convertible Senior Notes Securities Purchase Agreement dated September 16, 2010, by investors and accepted by McMoRan		10-Q	001-07791	11/09/2010
10.20	Form of 5.75% Convertible Perpetual Preferred Stock Securities Purchase Agreement dated September 16, 2010, by investors and accepted by McMoRan		10-Q	001-07791	11/09/2010
10.21	Purchase Agreement by and between McMoRan, McMoRan Oil & Gas LLC, as buyer, Whitney Exploration, LLC, as seller, and Stephen J. Williams, dated as of September 8, 2011		8-K	001-07791	09/09/2011
10.22*	McMoRan 1998 Stock Option Plan, as amended and restated		10-Q	001-07791	05/10/2007
10.23*	McMoRan 1998 Stock Option Plan for Non-Employee Directors		10-Q	001-07791	05/10/2007
10.24*	McMoRan Form of Notice of Grant of Nonqualified Stock Options under the 1998 Stock Option Plan		10-Q	001-07791	08/04/2005
10.25*	McMoRan 2000 Stock Incentive Plan, as amended and restated		10-Q	001-07791	05/10/2007
10.26*	McMoRan Form of Notice of Grant of Nonqualified Stock Options under the 2000 Stock Incentive Plan		10-Q	001-07791	08/04/2005

Exhibit Number	Exhibit Title	Filed with this Form 10-K	Incorporated by Reference		
			Form	File No.	Date Filed
10.27*	McMoRan 2001 Stock Incentive Plan, as amended and restated		10-Q	001-07791	05/10/2007
10.28*	McMoRan 2003 Stock Incentive Plan, as amended and restated		10-Q	001-07791	05/10/2007
10.29*	McMoRan's Performance Incentive Awards Program as amended December 1, 2008		10-K	001-07791	02/27/2009
10.30*	McMoRan Form of Notice of Grant of Nonqualified Stock Options under the 2001 Stock Incentive Plan		10-Q	001-07791	08/04/2005
10.31*	McMoRan Form of Restricted Stock Unit Agreement Under the 2001 Stock Incentive Plan		10-Q	001-07791	08/09/2007
10.32*	McMoRan Executive Services Program, as amended May 4, 2009		10-K	001-07791	03/12/2010
10.33*	McMoRan Form of Notice of Grants of Nonqualified Stock Options under the 2003 Stock Incentive Plan		10-Q	001-07791	08/04/2005
10.34*	McMoRan Form of Restricted Stock Unit Agreement Under the 2003 Stock Incentive Plan		10-Q	001-07791	08/09/2007
10.35*	McMoRan Amended and Restated 2004 Director Compensation Plan		10-Q	001-07791	08/09/2010
10.36*	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
10.37*	Amended and Restated Agreement for Consulting Services between FM Services Company and B.M. Rankin, Jr. effective as of January 1, 2010		10-K	001-07791	03/12/2010
10.38*	McMoRan Director Compensation (as of May 4, 2011)		10-Q	001-07791	05/06/2011
10.39*	McMoRan 2005 Stock Incentive Plan, as amended and restated		10-Q	001-07791	05/10/2007
10.40*	Form of Notice of Grant of Nonqualified Stock Options under the 2005 Stock Incentive Plan		8-K	001-07791	05/06/2005
10.41*	Form of Restricted Stock Unit Agreement under the 2005 Stock Incentive Plan		10-Q	001-07791	08/09/2007
10.42*	McMoRan Supplemental Executive Capital Accumulation Plan		10-Q	001-07791	05/08/2008
10.43*	McMoRan Supplemental Executive Capital Accumulation Plan Amendment One		10-Q	001-07791	05/08/2008
10.44*	McMoRan Supplemental Executive Capital Accumulation Plan Amendment Two		10-K	001-07791	02/27/2009
10.45*	McMoRan 2005 Supplemental Executive Capital Accumulation Plan		10-K	001-07791	02/27/2009
10.46*	McMoRan 2005 Supplemental Executive Capital Accumulation Plan Amendment One		10-Q	001-07791	05/10/2010
10.47*	McMoRan Amended and Restated 2008 Stock Incentive Plan		8-K	001-07791	05/04/2010

Exhibit Number	Exhibit Title	Filed with this Form 10-K	Incorporated by Reference Form	File No.	Date Filed
10.48*	Form of Notice of Grant of Nonqualified Stock Options under the 2008, 2005, 2003 and 2001 Stock Incentive Plans (adopted February 2011).		10-K	001-07791	02/28/2011
10.49*	Form of Restricted Stock Unit Agreement under the 2008, 2005, 2003 and 2001 Stock Incentive Plans (adopted February 2011)		10-K	001-07791	02/28/2011
10.50*	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
10.51*	McMoRan Severance Plan.		10-K	001-07791	02/27/2009
10.52*	Letter Agreement between Nancy Parmelee and FM Services Company (partially allocated to McMoRan)		10-K	001-07791	03/12/2010
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			
101.INS	XBRL Instance Document	X			
101.SCH	XBRL Taxonomy Extension Schema	X			
101.CAL	XBRL Taxonomy Extension Calculation Linkbase	X			
101.DEF	XBRL Taxonomy Extension Definition Linkbase.	X			
101.LAB	XBRL Taxonomy Extension Label Linkbase	X			
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	X			

* Indicates management contract or compensatory plan or agreement.

BOARD OF DIRECTORS

James R. Moffett
Co-Chairman of the Board,
President & Chief Executive Officer
McMoRan Exploration Co.

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

A. Peyton Bush, III [2]
President & Chief Executive Officer
Hibernia Bancorp, Inc.

William P. Carmichael [1]
Trustee
Columbia Funds

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

James C. Flores
Chairman of the Board,
President & Chief Executive Officer
Plains Exploration & Production
Company

Gerald J. Ford [1,3]
Chairman of the Board
Hilltop Holdings, Inc.
Chairman of the Board
Pacific Capital Bancorp.

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

Suzanne T. Mestayer [1,2]
Chief Executive Officer
ThirtyNorth Investments, LLC

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

John F. Wombwell
Executive Vice President,
General Counsel & Secretary
Plains Exploration & Production
Company

ADVISORY DIRECTORS

Dr. Morrison C. Bethea
Staff Physician
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

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

MANAGEMENT

James R. Moffett
Co-Chairman of the Board,
President & Chief Executive Officer

Richard C. Adkerson
Co-Chairman of the Board

OPERATIONS

Todd R. Cantrall
Senior Vice President –
Production Engineering
McMoRan Oil & Gas LLC

William E. Easton
Senior Vice President –
Reservoir Engineering
McMoRan Oil & Gas LLC

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

ADMINISTRATION AND FINANCE

John G. Amato
General Counsel

Thomas Beron
Assistant General Counsel
Senior Vice President – Land
McMoRan Oil & Gas LLC

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

Pamela Q. Masson
Vice President &
Chief Administrative Officer

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. Questions about lost certificates or notifications of change of address should, however, be directed to McMoRan's transfer agent and registrar, Computershare.

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

Computershare
480 Washington Boulevard
Jersey City, NJ 07310
888.208.1794
www.bnymellon.com/shareowner/equityaccess

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