Gulf Coast Ultra Deep Royalty Trust
Form 10-K
March 16, 2015

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, 2014
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: 001-36386

Gulf Coast Ultra Deep Royalty Trust
(Exact name of registrant as specified in its charter)

Delaware	46-6448579
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

The Bank of New York Mellon Trust Company, N.A., as trustee
Institutional Trust Services
919 Congress Avenue, Suite 500
Austin, Texas 78701
(Address of principal executive offices, including zip code)

(512) 236-6599

(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
Royalty Trust Units	The NASDAQ Stock Market LLC

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. o Yes x 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. o Yes x 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. x Yes o 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 that the registrant was required to submit and post such files). o Yes o 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. x

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 the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):
o Large accelerated filer x Accelerated filer o Non-accelerated filer (Do not check if a smaller reporting company) o Smaller reporting company

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

The aggregate market value of royalty trust units held by non-affiliates of the registrant was $384.5 million on June 30, 2014.

On February 28, 2015, there were outstanding 230,172,696 royalty trust units representing beneficial interests in the registrant.

DOCUMENTS INCORPORATED BY REFERENCE
NONE

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the fiscal year ended December 31, 2014
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FORWARD-LOOKING STATEMENTS

This Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements are all statements other than statements of historical facts, such as any statements regarding the future financial condition of Gulf Coast Ultra Deep Royalty Trust (the Royalty Trust), all statements regarding McMoRan Oil & Gas LLC's (McMoRan) plans for the subject interests, the potential results of any drilling on the subject interests (as defined in this Form 10-K) by the applicable operator, anticipated interests of McMoRan and the Royalty Trust in any of the subject interests, McMoRan's geologic model and the nature of the geologic trend in the Gulf of Mexico and onshore in South Louisiana discussed in this Form 10-K, and all statements regarding any belief or understanding of the nature or potential of the subject interests. The words "anticipates," "may," "can," "plans," "believes," "estimates," "expect "projects," "intends," "likely," "will," "should," "to be," "potential," and any similar expressions and/or statements that are not historical facts are intended to identify those assertions as forward-looking statements.

Forward-looking statements are not guarantees or assurances of future performance and actual results may differ materially from those anticipated, projected or assumed in the forward-looking statements. Important factors that may cause actual results to differ materially from those anticipated by the forward-looking statements include, but are not limited to, the risk that the subject interests will not produce hydrocarbons, general economic and business conditions, variations in the market demand for, and prices of, oil and natural gas, drilling results, changes in oil and natural gas reserve expectations, the potential adoption of new governmental regulations, decisions by FCX or McMoRan not to develop the subject interests, any inability of FCX or McMoRan to develop the subject interests, damages to facilities resulting from natural disasters or accidents and other factors described in Part I, Item 1A. "Risk Factors" of this Form 10-K.

Investors are cautioned that many of the assumptions upon which forward-looking statements are based are likely to change after such forward-looking statements are made, which the Royalty Trust cannot control. The Royalty Trust cautions investors that it does not intend to update its forward-looking statements, notwithstanding any changes in assumptions, changes in business plans, actual experience, or other changes, and the Royalty Trust undertakes no obligation to update any forward-looking statements except as required by law.

PART I

Items 1. and 2. Business and Properties

Our periodic and current reports filed or furnished with or to the Securities and Exchange Commission (SEC) pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (Exchange Act), as amended, are available, free of charge, through our website, http://gultu.investorhq.businesswire.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 or to the SEC.

References to "we," "us," and "our" refer to Gulf Coast Ultra Deep Royalty Trust (the Royalty Trust). References to "Notes" refer to the Notes to the Financial Statements included herein (refer to Part II, Item 8. "Financial Statements and Supplementary Data" 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 53.

THE ROYALTY TRUST

The Royalty Trust. On June 3, 2013, Freeport-McMoRan Inc. (FCX) and McMoRan Exploration Co. (MMR) completed the transactions contemplated by the Agreement and Plan of Merger, dated as of December 5, 2012 (the merger agreement), by and among MMR, FCX, and INAVN Corp., a Delaware corporation and indirect wholly owned subsidiary of FCX (Merger Sub). Pursuant to the merger agreement, Merger Sub merged with and into MMR, with MMR surviving the merger as an indirect wholly owned subsidiary of FCX (the merger).

FCX's portfolio of oil and gas assets is held through its wholly owned subsidiary, FCX Oil & Gas Inc. (FM O&G). As a result of the merger, MMR and McMoRan Oil & Gas LLC (McMoRan, MMR's wholly owned operating subsidiary) are both wholly owned subsidiaries of FM O&G.

The Royalty Trust was created as contemplated by the merger agreement, and is a statutory trust created by FCX under the Delaware Statutory Trust Act pursuant to a trust agreement entered into on December 18, 2012 (inception), by and among FCX, as depositor, Wilmington Trust, National Association, as Delaware trustee, and certain officers of FCX, as regular trustees. On May 29, 2013, Wilmington Trust, National Association, was replaced by BNY Trust of Delaware, as Delaware trustee (the Delaware Trustee), through an action of the depositor. Effective June 3, 2013, the regular trustees were replaced by The Bank of New York Mellon Trust Company, N.A., a national banking association, as trustee (the Trustee).

The Royalty Trust was created to hold a 5% gross overriding royalty interest (collectively, the overriding royalty interests) in future production from each of McMoRan's shallow water Inboard Lower Tertiary/Cretaceous exploration prospects located on the Shelf of the Gulf of Mexico and onshore in South Louisiana that existed as of December 5, 2012, the date of the merger agreement (collectively, the subject interests). The subject interests were "carved out" of the mineral interests that were acquired by FCX pursuant to the merger and were not considered part of FCX's purchase consideration of MMR. McMoRan owns less than 100% of the working interest associated with each of the subject interests.

Impairment charges totaling $231.7 million, representing the carrying value associated with thirteen of the subject interests, were recorded for the year ended December 31, 2014. McMoRan has informed the Trustee that due to the sharp decline in oil prices during the fourth quarter of 2014, budgeted 2015 capital expenditures were reduced and near-term activities on all subject interests except for the onshore Highlander subject interest have been deferred. As a result of these factors and well-specific data, McMoRan does not plan to drill or conduct operational activities on the thirteen subject interests prior to their lease expiration dates, which required an impairment of their carrying values. In the event on or before December 5, 2017, McMoRan acquires a leasehold interest covering the same area and block covered by a terminated lease, or acquires additional leasehold interests associated with the subject interests, such newly acquired leasehold interests shall become subject interests.

As described below, as of December 31, 2014, only the onshore Lineham Creek and Highlander subject interests had any reserves classified as proved, probable or possible and none of the subject interests had any associated commercial production. The onshore Highlander subject interest began commercial production on February 25, 2015.

The overriding royalty interests are passive in nature, and neither the Trustee nor the Royalty Trust unitholders has any control over or responsibility for any costs relating to the drilling, development or operation of the subject interests. The Royalty Trust is not permitted to acquire other oil and natural gas properties or mineral interests or otherwise engage in activities beyond those necessary for the conservation and protection of the overriding royalty interests.
As of December 31, 2014, FCX beneficially owned 27.1% of the outstanding royalty trust units. All information in this Form 10-K regarding the subject interests has been furnished to the Trustee by FCX and McMoRan. The reserve estimates have been prepared by independent petroleum engineers as described herein, based on information furnished by FM O&G.

The Royalty Trust Agreement. In connection with the merger, on June 3, 2013, (1) FCX, as depositor, McMoRan, as grantor, the Trustee and the Delaware Trustee, entered into the amended and restated royalty trust agreement to govern the Royalty Trust and the respective rights and obligations of FCX, the Trustee, the Delaware Trustee, and the Royalty Trust unitholders with respect to the Royalty Trust (the royalty trust agreement); and (2) McMoRan, as grantor, and the Royalty Trust, as grantee, entered into the master conveyance of overriding royalty interest (the master conveyance) pursuant to which McMoRan conveyed to the Royalty Trust the overriding royalty interests in future production from the subject interests.

Duties and Limited Powers of the Trustee. The duties of the Trustee are specified in the royalty trust agreement and by the laws of the State of Delaware. The Trustee's principal duties consist of:

- collecting income attributable to the overriding royalty interests;
- paying expenses, charges and obligations of the Royalty Trust from the Royalty Trust's income and assets;
- distributing distributable income to the Royalty Trust unitholders; and

- prosecuting, defending or settling any claim of or against the Trustee, the Royalty Trust or the overriding royalty interests, including the authority to dispose of or relinquish title to any of the overriding royalty interests that are the subject of a dispute upon the receipt of sufficient evidence regarding the facts of such dispute.

The Trustee has no authority to incur any contractual liabilities on behalf of the Royalty Trust that are not limited solely to claims against the assets of the Royalty Trust.

If a liability is contingent or uncertain in amount or not yet currently due and payable, the Trustee may create a cash reserve to pay for the liability. If the Trustee determines that the cash on hand and the cash to be received are insufficient to cover expenses or liabilities of the Royalty Trust, the Trustee may borrow funds required to pay those expenses or liabilities. The Trustee may borrow the funds from any person, including FCX or itself. The Trustee may also encumber the assets of the Royalty Trust (i.e., the overriding royalty interests) to secure payment of the indebtedness. If the Trustee borrows funds, whether from FCX or from any other source, to cover expenses or liabilities, the Royalty Trust unitholders will not receive distributions until the borrowed funds are repaid. Since the Royalty Trust does not conduct an active business and the Trustee has little power to incur obligations, it is expected that the Royalty Trust will only incur liabilities for routine administrative expenses, such as the Trustee’s fees and accounting, engineering, legal, tax advisory and other professional fees.

The only assets of the Royalty Trust are the overriding royalty interests and the only investment activity the Trustee may engage in is the investment of cash on hand. Other than (a) its formation, (b) its receipt of contributions and loans from FCX for administrative and other expenses as provided for in the royalty trust agreement, (c) its payment of such administrative and other expenses and (d) its receipt of the conveyance of the overriding royalty interests from McMoRan pursuant to the master conveyance, the Royalty Trust has not conducted any activities.

The Trustee has the right to require any Royalty Trust unitholder to dispose of his royalty trust units if an administrative or judicial proceeding seeks to cancel or forfeit any of the property in which the Royalty Trust holds an interest because of the nationality or any other status of a Royalty Trust unitholder. If a Royalty Trust unitholder fails to dispose of his royalty trust units, FCX is obligated to purchase them (up to a cap of $1 million) at a price determined in accordance with a formula set forth in the royalty trust agreement.

The Trustee is authorized to agree to modifications of the terms of the conveyances of the overriding royalty interests or to settle disputes involving such conveyances, so long as such modifications or settlements do not alter the nature of the overriding royalty interests as rights to receive a share of the proceeds from the underlying properties free of any obligation for drilling, development or operating expenses or rights that do not possess any operating rights or obligations.

Pursuant to the royalty trust agreement, FCX has agreed to pay annual trust expenses up to a maximum amount of $350,000, with no right of repayment or interest due, to the extent the Royalty Trust lacks sufficient funds to pay administrative expenses. During each of the years ended December 31, 2014 and 2013, FCX contributed $350,000 to the Royalty Trust with respect to this arrangement. In addition to such annual contributions, FCX has agreed to lend money, on an unsecured, interest-free basis, to the Royalty Trust to fund the Royalty Trust's ordinary administrative expenses as set forth in the royalty trust agreement. During the years ended December 31, 2014 and 2013, FCX loaned $200,000 and $450,000, respectively, to the Royalty Trust under this arrangement, none of which has been repaid as of December 31, 2014.

Pursuant to the royalty trust agreement, FCX agreed to provide and maintain a $1.0 million stand-by reserve account or an equivalent letter of credit for the benefit of the Royalty Trust to enable the Trustee to draw on such reserve account or letter of credit to pay obligations of the Royalty Trust in the event that it has inadequate funds to pay its obligations at any time. Currently, with the consent of the Trustee, FCX may reduce the reserve account or substitute a letter of credit with a different face amount for the original letter of credit or any substitute letter of credit. In connection with this arrangement, FCX has provided $1.0 million in the form of a reserve fund cash account to the Royalty Trust. The Royalty Trust has not drawn any funds from the reserve account, and FCX has not requested a reduction of such reserve account.

Fiduciary Responsibility and Liability of the Trustee. The duties and liabilities of the Trustee are set forth in the royalty trust agreement and the laws of the State of Delaware. The Trustee may not make business decisions affecting the assets of the Royalty Trust. Therefore, substantially all of the Trustee's functions under the royalty trust agreement are expected to be ministerial in nature. See the description in the section above entitled "Duties and Limited Powers of the Trustee." The royalty trust agreement, however, provides that the Trustee may:

- charge for its services as trustee;
- retain funds to pay for future expenses and deposit them with one or more banks or financial institutions (which may include the trustee to the extent permitted by law);
- lend funds at commercial rates to the Royalty Trust to pay the Royalty Trust's expenses (however, the Trustee does not intend to lend funds to the Royalty Trust); and
- seek reimbursement from the Royalty Trust for its out-of-pocket expenses.

In performing its duties to Royalty Trust unitholders, the Trustee may act in its discretion and is liable to the Royalty Trust unitholders only for willful misconduct, bad faith or gross negligence. The Trustee is not liable for any act or omission of its agents or employees unless the Trustee acted with willful misconduct, bad faith or gross negligence in its selection and retention. The Trustee will be indemnified individually or as trustee out of the Royalty Trust's assets for any liability or cost that it incurs in the administration of the Royalty Trust, except in cases of willful misconduct, bad faith or gross negligence. The Trustee has a lien on the assets of the Royalty Trust as security for this indemnification and its compensation earned as trustee. The Royalty Trust unitholders are not liable to the Trustee for any indemnification. The Trustee ensures that all contractual liabilities of the Royalty Trust are limited to the assets of the Royalty Trust.

Protection of Trustee. Pursuant to the royalty trust agreement, the Trustee may request certification of any fact, circumstance, computation or other matter relevant to the Royalty Trust or the Trustee's performance of its duties, and will be fully protected in relying on any such certification or other statement or advice from FCX or McMoRan or any officer or other employee of FCX or McMoRan. Any person having any claim against the Trustee by reason of the transactions contemplated by the royalty trust agreement or any of the related documents or agreements shall look only to the Royalty Trust's property for payment or satisfaction thereof.
Amendment of Trust Agreement. Amendments to the royalty trust agreement generally require a vote of holders of a majority of royalty trust units constituting a quorum, although less than a majority of the royalty trust units then outstanding (including any royalty trust units held by FCX, other than with respect to matters where a conflict of interest between FCX and unaffiliated Royalty Trust unitholders is present). However, any amendment that would permit holders of fewer than 80% (which, after June 3, 2018, shall be reduced to 66 %) of the outstanding royalty trust units to approve a sale of all or substantially all of the overriding royalty interests, or to terminate the Royalty Trust requires a vote of holders of 80% (which, after June 3, 2018, shall be reduced to 66 %) or more of the outstanding royalty trust units held by persons other than FCX or its affiliates.

FCX and the Trustee are permitted to supplement or amend the royalty trust agreement, without the approval of the Royalty Trust unitholders, in order to cure any ambiguity, to correct or supplement any provision which may be defective or inconsistent with any other provision thereof, or to change the name of the Royalty Trust, provided that such supplement or amendment does not adversely affect the interests of the Royalty Trust unitholders. However, no amendment may:

- alter the purposes of the Royalty Trust or permit the Trustee to engage in any business or investment activities other than as specified in the royalty trust agreement;

- alter the rights of the Royalty Trust unitholders as among themselves;
- permit the Trustee to distribute the overriding royalty interests in kind; or
- adversely affect the rights and duties of the Trustee unless such amendment is approved by the Trustee.

Compensation of the Trustee. The Trustee is paid the sum of $150,000 per year until the first year in which the Royalty Trust receives any payment pursuant to the conveyances of the overriding royalty interests, at which time such sum will be increased to $200,000 per year. The onshore Highlander subject interest began commercial production on February 25, 2015. Accordingly, it is anticipated that the Trustee will be paid $200,000 per year beginning in 2015. Additionally, the Trustee receives reimbursement for its reasonable out-of-pocket expenses incurred in connection with the administration of the Royalty Trust. In the event of litigation involving the Royalty Trust, audits or inspection of the records of the Royalty Trust pertaining to the transactions affecting the Royalty Trust or any other unusual or extraordinary services rendered in connection with the administration of the Royalty Trust, the Trustee would be entitled to receive additional reasonable compensation for the services rendered, including the payment of the Trustee’s standard rates for all time spent by personnel of the Trustee on such matters. The Trustee’s compensation is paid out of the Royalty Trust's assets. The Trustee has a lien on the Royalty Trust’s assets to secure payment of its compensation and any indemnification expenses and other amounts to which it is entitled under the royalty trust agreement.

Approval of Matters by Royalty Trust Unitholders. The Trustee or Royalty Trust unitholders owning at least 15% of the outstanding royalty trust units are permitted to call meetings of Royalty Trust unitholders. Meetings must be held in New York, New York. Written notice setting forth the time and place of the meeting and the matters proposed to be acted upon must be given to all Royalty Trust unitholders of record as of a record date set by the Trustee at least 20 days but not more than 60 days before the meeting. The presence in person or by proxy of Royalty Trust unitholders representing a majority of royalty trust units outstanding will constitute a quorum. Subject to the provisions of the royalty trust agreement regarding voting in the case of a material conflict of interest between FCX or its affiliates, and Royalty Trust unitholders other than FCX or its affiliates, each Royalty Trust unitholder will be entitled to one vote for each royalty trust unit owned.

Unless otherwise required by the royalty trust agreement, any matter (including unit splits or reverse splits) may be approved by holders of a majority of royalty trust units constituting a quorum, although less than a majority of the royalty trust units then outstanding (including any royalty trust units held by FCX, other than with respect to matters where a conflict of interest between FCX and unaffiliated Royalty Trust unitholders is present). The affirmative vote of the holders of 80% (which, after June 3, 2018, shall be reduced to 66 %) of the outstanding royalty trust units will be required to (i) approve a sale of all or substantially all of the overriding royalty interests, (ii) terminate the Royalty Trust or (iii) amend the royalty trust agreement to permit the holders of fewer than 80% (which, after June 3, 2018, shall be reduced to 66 %) of the outstanding royalty trust units to approve a sale of all or substantially all of the overriding royalty interests, or to terminate the Royalty Trust.

The Trustee may be removed, with or without cause, by a vote of the holders of a majority of the outstanding royalty trust units.
Any action required or permitted to be authorized or taken at any meeting of Royalty Trust unitholders may be taken without a meeting, without prior notice and without a vote if a consent in writing setting forth the authorization or action taken is signed by Royalty Trust unitholders holding royalty trust units representing at least the minimum number of votes that would be necessary to authorize or take such action at a meeting.
If a meeting of Royalty Trust unitholders is called for any purpose or a written consent is executed at the request of any Royalty Trust unitholder while the Royalty Trust is subject to the requirements of Section 12 of the Exchange Act, the Royalty Trust unitholder requesting the meeting or soliciting the written consent will be required to prepare and file a proxy or information statement with the SEC regarding such meeting or written consent at its expense. The Royalty Trust unitholder requesting the meeting or written consent will bear the expense of distributing the notice of meeting and the proxy or information statement. The Trustee will be required only to provide a list of Royalty Trust unitholders to the extent required by law.

Duration of the Royalty Trust. The Royalty Trust will dissolve on the earlier of (i) June 3, 2033, (ii) the sale of all of the overriding royalty interests, (iii) the election by the Trustee following its resignation for cause (as more fully described in the royalty trust agreement), (iv) a vote of the holders of 80% (which after June 3, 2018, shall be reduced to 66 %) or more of the outstanding royalty trust units held by persons other than FCX or any of its affiliates, at a duly called meeting of the Royalty Trust unitholders at which a quorum is present, or (v) the exercise by FCX of the right to call all of the royalty trust units as described in the next paragraph. The overriding royalty interests terminate upon the termination of the Royalty Trust, other than in certain limited circumstances where the Royalty Trust has been permitted to transfer the overriding royalty interests to a third party pursuant to the terms of the royalty trust agreement (in which case the overriding royalty interests may extend through June 3, 2033).

FCX Call Rights. FCX has a call right with respect to the outstanding royalty trust units at $10 per royalty trust unit, provided that the call right may not be exercised prior to June 3, 2018. In addition, at any time after June 3, 2018, if the royalty trust units are then listed for trading or admitted for quotation on a national securities exchange or any quotation system and the volume weighted average price per royalty trust unit is equal to $0.25 or less for the immediately preceding consecutive nine-month period, FCX may purchase all, but not less than all, of the outstanding royalty trust units at a price of $0.25 per royalty trust unit so long as FCX tenders payment within 30 days of such nine-month period.

Resignation of Trustee. The Trustee may resign, with or without cause, at any time by providing at least 60 days' notice to FCX and the Royalty Trust unitholders of record, but the resignation of the Trustee will not be effective until a successor trustee has accepted its appointment. The Trustee may nominate a successor trustee, which may be approved and appointed by FCX without a meeting or vote of the Royalty Trust unitholders. If the Trustee has given notice of resignation for cause and a successor trustee has not accepted its appointment as successor trustee during the 90-day period following the receipt by FCX of such notice, the annual fee payable to the Trustee will be increased as of the end of such 90-day period by 5%, and will be further increased by 5% for each month or portion of a month thereafter (up to a maximum of two times the fee payable at the time the notice of resignation was received by FCX) until a successor trustee has accepted its appointment.

If at any time (a) the Trustee has not received compensation for its services or expenses or other amounts owed to the Trustee pursuant to the royalty trust agreement, (b) FCX has failed to fully fund a loan to the Royalty Trust in a reasonably timely manner after the Trustee has requested the loan pursuant to the royalty trust agreement or has failed to contribute funds to the Royalty Trust as required by the royalty trust agreement, (c) the Royalty Trust's obligations exceed the amount of funds of the Royalty Trust available to pay such obligations, and (d) a stand-by reserve account or letter of credit is available to the Trustee as described in the royalty trust agreement, the Trustee is entitled to draw on the stand-by reserve account or letter of credit, then the Trustee would be permitted to resign for cause, and would be entitled to cause the sale of the overriding royalty interests and to dissolve, windup and terminate the Royalty Trust.

Overriding Royalty Interests. The royalty trust units represent beneficial interests in the Royalty Trust, which holds a 5% gross overriding royalty interest in future production from each of the subject interests during the life of the Royalty Trust. An "overriding" royalty interest in general represents a non-operating interest in an oil and gas property that provides the owner a specified share of production without any related operating expenses or development costs and is carved out of an oil and gas lessee's working or cost-bearing interest. In contrast, a "working" or "cost-bearing" interest in general represents an operating interest in an oil and gas property that provides the owner a specified share of production that is subject to all production expenses and development costs. An owner of a working or cost-bearing interest, subject to the terms of an applicable operating agreement, generally has the right to participate in the selection of a prospect, drilling location, or drilling contractor, to propose the drilling of a well, to determine the timing and sequence of drilling operations, to commence or shut down production, to take over operations, or to share in any operating decision. An owner of an overriding royalty interest in general has none of the rights described in the preceding sentence, and neither the Royalty Trust nor the Royalty Trust unitholders have any such rights.

The overriding royalty interests are free and clear of any and all drilling, development and operating costs and expenses, except that the overriding royalty interests bear a proportional share of costs incurred for activities downstream of the wellhead for gathering, transporting, compressing, treating, handling, separating, dehydrating or processing the produced hydrocarbons prior to their sale, and certain production, severance, sales, excise and similar taxes related to the sale of the produced hydrocarbons and property or ad valorem taxes to the extent assessed on the subject interests (the specified post-production costs and specified taxes, respectively). The hydrocarbons underlying the overriding royalty interests are valued at the wellhead (after deduction or withholding of specified taxes and less any specified post-production costs) and neither McMoRan nor FCX has any duty to transport or market the produced hydrocarbons away from the wellhead without cost. The hydrocarbons underlying the overriding royalty interests are subject to and bear production and other like taxes.

Royalty Trust Units. Each royalty trust unit represents a pro rata undivided share of beneficial ownership in the Royalty Trust. Each royalty trust unit entitles its holder to the same rights and benefits as the holder of any other royalty trust unit, and the Royalty Trust has no other authorized or outstanding class of equity security.

Distributions and Income Computations. Each quarter, the Trustee determines the amount of funds, if any, available for distribution to the Royalty Trust unitholders. Available funds will equal the excess cash, if any, received by the Royalty Trust from the overriding royalty interests and other sources during that quarter over the Royalty Trust's liabilities for that quarter. In any event, no distributions will be made until such time as the Trustee receives cash proceeds from the overriding royalty interests. Available funds will be further reduced by any cash the Trustee determines to hold as a reserve against future liabilities. The Trustee shall establish a cash reserve equal to such amount. Royalty Trust unitholders that own their royalty trust units on the close of business on the record date for each calendar quarter will receive a pro-rata distribution of the amount of the cash available for distribution, if any, generally 10 business days after the quarterly record date.

Unless otherwise advised by counsel or the Internal Revenue Service (IRS), the Trustee will record the income and expenses of the Royalty Trust for each quarterly period as belonging to the Royalty Trust unitholders of record on the quarterly record date. The Royalty Trust unitholders will recognize income and expenses for tax purposes in the quarter of receipt or payment by the Royalty Trust, rather than in the quarter of distribution by the Royalty Trust. Minor variances may occur; for example, a reserve could be established in one quarterly period that would not give rise to a tax deduction until a later quarterly period, or an expenditure paid in one quarterly period might be amortized for tax purposes over several quarterly periods.

Transfer of the Royalty Trust Units. Royalty Trust unitholders are permitted to transfer their royalty trust units in accordance with the royalty trust agreement. The Trustee will not require either the transferor or transferee to pay a service charge for any transfer of a royalty trust unit. The Trustee may require payment of any tax or other governmental charge imposed for a transfer. The Trustee may treat the owner of any royalty trust unit as shown by its records as the owner of the royalty trust unit. The Trustee will not be considered to know about any claim or demand on a royalty trust unit by any party except the record owner. A person who acquires a royalty trust unit after any quarterly record date will not be entitled to the distribution relating to that quarterly record date. Delaware law and the royalty trust agreement will govern all matters affecting the title, ownership or transfer of royalty trust units.

Periodic Reports. Within 40 days following the end of each of the first three fiscal quarters, and within 75 days following the end of each fiscal year, the Royalty Trust files a quarterly report on Form 10-Q, or annual report on Form 10-K, as appropriate, with the SEC.

The Royalty Trust files all required federal and state income tax and information returns. Within 75 days following the end of each fiscal year, the Royalty Trust prepares and mails to each Royalty Trust unitholder of record as of a quarterly record date during such year a report in reasonable detail with the information that Royalty Trust unitholders need to correctly report their share of the income and deductions of the Royalty Trust.

The royalty trust agreement also requires FCX or McMoRan to provide to the Royalty Trust such other information available to FCX or McMoRan concerning the overriding royalty interests and the subject interests burdened by the overriding royalty interests and related matters as may be necessary for the Royalty Trust to comply with its reporting obligations. In addition, the royalty trust agreement requires FCX or McMoRan to provide to the Royalty Trust all information required to comply with the requirements of the Exchange Act (including a “Trustee’s Discussion and Analysis of Financial Condition and Results of Operations” relating to the Royalty Trust's financial statements) and such further information as may be required or reasonably requested by the Trustee from time to time. Pursuant to the royalty trust agreement, the Royalty Trust and the Trustee are entitled to rely on the information provided by FCX or McMoRan without investigation and are fully protected and shall incur no liability in doing so. However, neither FCX nor McMoRan nor their affiliates may be required to disclose, produce or prepare any information, documents or other materials which were generated for analysis or discussion purposes, contain interpretative data, or are subject to the attorney-client or attorney-work-product privileges, or any other privileges to which they may be entitled pursuant to applicable law.

A Royalty Trust unitholder and his representatives may examine, during reasonable business hours and at the expense of such Royalty Trust unitholder, the records of the Royalty Trust and the Trustee.

Liability of the Royalty Trust Unitholders and the Royalty Trust. Under the Delaware Statutory Trust Act, Royalty Trust unitholders are entitled to the same limitation of personal liability extended to stockholders of private for-profit corporations under the Delaware General Corporation Law. No assurance can be given, however, that the courts in jurisdictions outside of Delaware will give effect to such limitation of personal liability.

Uncertificated Interests; Transfer Agent. The royalty trust units are uncertificated, and ownership of the royalty trust units is evidenced by entry of a notation in an ownership ledger maintained by the Trustee or a transfer agent designated by the Trustee. The transfer agent is American Stock Transfer & Trust Company, LLC. The Trustee may dismiss the transfer agent and designate a successor transfer agent at any time.

THE SUBJECT INTERESTS

The subject interests consist of 20 specified shallow water Inboard Lower Tertiary/Cretaceous prospects (which have target depths generally greater than 18,000 feet total vertical depth) located on the Shelf of the Gulf of Mexico and onshore in South Louisiana, one of which is under development and the rest of which are exploration prospects. The offshore subject interests consist of the following exploration prospects: (1) Barataria; (2) Barbosa; (3) Blackbeard East; (4) Blackbeard West; (5) Blackbeard West #3; (6) Bonnet; (7) Calico Jack; (8) Captain Blood; (9) Davy Jones; (10) Davy Jones West; (11) Drake; (12) England; (13) Hook; (14) Hurricane; (15) Lafitte; (16) Morgan; and (17) Queen Anne's Revenge. The onshore subject interests consist of (1) Highlander; (2) Lineham Creek; and (3) Tortuga. With the exception of the onshore Highlander subject interest, which is currently under development, the onshore subject interests are currently exploration prospects. McMoRan does not own 100% of the estimated working interest associated with any of the subject interests. The overriding royalty interests in future production from the subject interests burden all of McMoRan's leasehold interests associated with such prospects as of December 5, 2012, and will burden any leasehold interests associated with such prospects which are acquired by McMoRan on or before December 5, 2017, up to the estimated working interests reflected in the table below (subject to McMoRan's right to dispose of a portion of the working interests to a percentage not less than the estimated working interests reflected in the table below). Each of the overriding royalty interests has been, or will be, proportionately reduced based on McMoRan's working interest to equal the product of 5% multiplied by a fraction, the numerator of which is the working interest held by McMoRan and its affiliates associated with the applicable subject interest (subject to a cap equal to McMoRan's estimated working interest (equal to the working interest McMoRan owns or expects to acquire and as reflected in the table below) associated with each subject interest, on a prospect by prospect basis) and the denominator of which is 100%.

As of December 5, 2012, the date of the merger agreement, the subject interests comprised all of McMoRan's Inboard Lower Tertiary/Cretaceous exploration prospects. Additional Inboard Lower Tertiary/Cretaceous exploration prospects developed by McMoRan (other than those reflected below) will not be included in the subject interests. As of December 31, 2014, McMoRan had acquired working interests in additional Inboard Lower Tertiary/Cretaceous exploration prospects that are not part of the subject interests.

Impairment charges totaling $231.7 million, representing the carrying value associated with thirteen of the subject interests, were recorded for the year ended December 31, 2014. McMoRan has informed the Trustee that due to the sharp decline in oil prices during the fourth quarter of 2014, budgeted 2015 capital expenditures were reduced and near-term activities on all subject interests except for the onshore Highlander subject interest have been deferred. As a result of these factors and well-specific data, McMoRan does not plan to drill or conduct operational activities on the thirteen subject interests prior to their lease expiration dates, which required an impairment of their carrying values. In the event on or before December 5, 2017, McMoRan acquires a leasehold interest covering the same area and block covered by a terminated lease, or acquires additional leasehold interests associated with the subject interests, such newly acquired leasehold interests shall become subject interests.

As described below, as of December 31, 2014, only the onshore Lineham Creek and Highlander subject interests had any reserves classified as proved, probable or possible and none of the subject interests had any associated commercial production. The onshore Highlander subject interest began commercial production on February 25, 2015. Approximately 2.1 Bcfe of estimated proved reserves related to the onshore Lineham Creek and Highlander subject interests are currently deemed attributable to the applicable overriding royalty interest proportionately reduced to reflect McMoRan's estimated working interest.

Information regarding McMoRan's estimated working interest and the Royalty Trust's estimated overriding royalty interest for each subject interest as of December 31, 2014 is set forth below.

Subject Interest	McMoRan's Estimated Working Interest Related to the Subject Interests	Operator	Royalty Trust's Estimated Overriding Royalty Interest (5% proportionately reduced to reflect the Estimated Working Interest)
Davy Jones [a]	63.4%	McMoRan	3.17%
Blackbeard East [b]	—	McMoRan	—
Lafitte [c]	72%	McMoRan	3.6%
Blackbeard West [d]	69.4%	McMoRan	3.47%
England [e]	36%	Chevron	1.8%
Barbosa [f]	—	McMoRan	—
Morgan [g]	—	McMoRan	—
Barataria [h]	72%	McMoRan	3.6%
Blackbeard West #3 [d]	69.4%	McMoRan	3.47%
Drake [h]	72%	McMoRan	3.6%
Davy Jones West [i]	36%	McMoRan	1.8%
Hurricane [i]	72%	McMoRan	3.6%
Hook [h]	72%	McMoRan	3.6%
Captain Blood [h]	72%	McMoRan	3.6%
Bonnet [h]	72%	McMoRan	3.6%
Queen Anne's Revenge [j]	—	McMoRan	—
Calico Jack [h]	36%	McMoRan	1.8%
Highlander	72%	McMoRan	3.6%
Lineham Creek	36%	Chevron	1.8%
Tortuga	72%	McMoRan	3.6%

(a) McMoRan has informed the Trustee that it does not plan to further develop the offshore Davy Jones subject interest prior to its third-quarter 2015 lease expiration. As such, an impairment charge of $26.9 million, representing the carrying value associated with the Davy Jones subject interest, was recorded during fourth quarter 2014 (See Note 1).

(b) In January 2015, McMoRan requested from the BSEE that its then pending request for a revised Suspension of Production (SOP) for the Blackbeard East unit be withdrawn, which effectively relinquished McMoRan's lease rights to the Blackbeard East unit as of December 31, 2014. As such, an impairment charge of $11.5 million, representing the carrying value associated with the offshore Blackbeard East subject interest, was recorded during fourth quarter 2014 (See Note 1). In the event on or before December 5, 2017, McMoRan acquires a leasehold interest covering the same area and block covered by the terminated lease, or acquires additional leasehold interests associated with the Blackbeard East subject interest, such newly acquired leasehold interests shall become part of the Blackbeard East subject interest, and if this were to occur, it is expected that McMoRan would hold an approximate 72% working interest in such acquired/reacquired leases, equating to an estimated overriding royalty interest of 3.6% to be held by the Royalty Trust.

(c) In June 2013, McMoRan relinquished its previously-held lease rights to the Lafitte prospect, and in June 2014, McMoRan received notice from the BOEM that its bid for the lease rights to Eugene Island 223 (associated with the offshore Lafitte subject interest) was accepted. McMoRan's rights to this reacquired lease became effective August 1, 2014, and such lease is now subject to the overriding royalty interests held by the Royalty Trust.

(d) McMoRan has informed the Trustee that it does not plan to further develop the Blackbeard West unit prior to its second-quarter 2015 lease expiration. As such, impairment charges totaling $24.9 million, representing the carrying value associated with the offshore Blackbeard West and Blackbeard West #3 subject interests, were recorded during fourth quarter 2014 (See Note 1).

(e) In June 2014, McMoRan received notice from the BOEM that its bids for the lease rights to Vermillion 17, 38 and 39 (associated with the offshore England subject interest) were accepted. McMoRan's rights to these leases became effective July 1, 2014, and such leases are now subject to the overriding royalty interests held by the Royalty Trust.

(f) McMoRan's rights to the Barbosa lease expired on June 30, 2014. During first-quarter 2014, an impairment charge of $28.6 million, representing the carrying value associated with the offshore Barbosa subject interest, was recorded as drilling activities were not expected to occur on this subject interest prior to its lease expiration date (See Note 1). In the event on or before December 5, 2017, McMoRan acquires a leasehold interest covering the same area and block covered by the terminated lease, or acquires additional leasehold interests associated with the Barbosa subject interest, such newly acquired leasehold interests shall become part of the Barbosa subject interest, and if this were to occur, it is expected that McMoRan would hold an approximate 72% working interest in such acquired/reacquired leases, equating to an estimated overriding royalty interest of 3.6% to be held by the Royalty Trust.

(g) McMoRan's rights to the Morgan lease expired on May 31, 2013. In the event on or before December 5, 2017, McMoRan acquires a leasehold interest covering the same area and block covered by the terminated lease, or acquires additional leasehold interests associated with the offshore Morgan subject interest, such newly acquired leasehold interests shall become part of the Morgan subject interest, and if this were to occur, it is expected that McMoRan would hold an approximate 72% working interest in such acquired/reacquired leases, equating to an estimated overriding royalty interest of 3.6% to be held by the Royalty Trust.

(h) McMoRan has informed the Trustee that it does not plan to develop the offshore Barataria, Drake, Hook, Captain Blood, Bonnet and Calico Jack subject interests prior to their 2015 lease expiration dates. As such, impairment charges totaling $119.9 million, representing the carrying value associated with these subject interests, were recorded during fourth quarter 2014 (See Note 1).

(i) McMoRan has informed the Trustee that it does not plan to develop the offshore Davy Jones West and Hurricane subject interests. As such, impairment charges totaling $19.9 million, representing the carrying value associated with these subject interests, were recorded during fourth quarter 2014 (See Note 1).

(j) McMoRan's rights to the leases associated with the offshore Queen Anne's Revenge subject interest expired on December 31, 2014. In the event on or before December 5, 2017, McMoRan acquires one or more leasehold interests covering the same area and blocks covered by the terminated leases, or acquires additional leasehold interests associated with the Queen Anne's Revenge subject interest, such newly acquired leasehold interests shall become part of the Queen Anne's Revenge subject interest, and if this were to occur, it is expected that McMoRan would hold an approximate 72% working interest in such acquired/reacquired leases, equating to an estimated overriding royalty interest of 3.6% to be held by the Royalty Trust.

Exploratory and Development Drilling. The following table provides the total number of wells that McMoRan drilled on the subject interests during the years ended December 31, 2014 and 2013.

	Year Ended December 31, 2014		Year Ended December 31, 2013	
	Gross	Net	Gross	Net
Exploratory				
Productive:				
Oil	—	—	—	—
Gas	—	—	—	—
Dry	5	3	—	—
	5	3	—	—
Development				
Productive:				
Oil	—	—	—	—
Gas	—	—	—	—
Dry	—	—	—	—
	—	—	—	—
	5	3	—	—

The five dry wells included in the table above are the Blackbeard East well whose lease unit expired on December 31, 2014, the Davy Jones No. 1 and Davy Jones No. 2 wells, both of which had unsuccessful flow test attempts and the Blackbeard West No. 1 and No. 2 wells, both of which had noncommercial results. Each of these five dry wells were drilled in prior years and completed in 2014. For the purpose of this table, the term "completed" refers to the installation of permanent equipment for the production of oil or natural gas or, in the case of a dry well, to reporting to the appropriate authority that the well has been abandoned. In addition to the wells drilled during 2014, there were two gross (one net) in-progress well associated with the subject interests at December 31, 2014. There were seven gross (four net) in-progress and/or suspended wells associated with the subject interests at December 31, 2013. As discussed above, McMoRan has informed the Trustee that due to the sharp decline in oil prices during the fourth quarter of 2014, budgeted 2015 capital expenditures were reduced and near-term activities on all subject interests except for the onshore Highlander subject interest have been deferred.

In December 2014, a production test performed in the Cretaceous/Tuscaloosa section on the onshore Highlander subject interest indicated a flow rate of approximately 43.5 million cubic feet of natural gas per day (MMcf/d), approximately 21 MMcf/d net to McMoRan, on a 22/64th choke with flowing tubing pressure of 11,880 pounds per square inch. In February 2015, FCX announced the results of additional production testing on the onshore Highlander subject interest, that utilized expanded testing equipment indicated a flow rate of approximately 75 MMcf/d, approximately 37 MMcf/d net to McMoRan, on a 42/64th choke with flowing tubing pressure of 10,300 pounds per square inch. The onshore Highlander subject interest began commercial production on February 25, 2015, using McMoRan facilities in the immediate area. McMoRan plans to install additional amine processing facilities to accommodate the higher rates. A second well location has been identified and future plans will be determined pending review of performance of the first well. McMoRan has identified multiple prospects in the Highlander area where McMoRan controls rights to more than 50,000 gross acres. Independent reserve engineer's estimates of proved reserves as of December 31, 2014 for the onshore Highlander subject interest reflect reserves attributable solely to the initial well. McMoRan believes that the well tests and geologic data from the initial well confirm the highly prospective potential in the Highlander area.

Acreage. At December 31, 2014, McMoRan owned or controlled (through options to lease) interests in approximately 1,427 oil and gas leases on the Shelf of the Gulf of Mexico and onshore in South Louisiana, covering approximately 324,000 gross acres (195,000 acres net to McMoRan's interests) associated with the subject interests. Approximately 42%, 3% and 23% of those net acres associated with the subject interests are scheduled to expire during 2015, 2016 and 2017, respectively. McMoRan has informed the Trustee that it does not plan to further develop the offshore Davy Jones, Blackbeard West and Blackbeard West #3 subject interests and does not plan to commence development of the offshore Barataria, Drake, Hook, Captain Blood, Bonnet and Calico Jack subject interests, prior to their respective lease expirations in 2015. Additionally, McMoRan has informed the Trustee that it does not plan to develop the offshore Davy Jones West and Hurricane subject interests (See Note 3).

Owned and optioned acreage can be retained by McMoRan through commencement or recommencement of operations or through the exercise of options, as applicable. Whether McMoRan will develop acreage that is scheduled to expire is subject to McMoRan's current and future drilling plans, over which the Royalty Trust has no control. The following table reflects the oil and gas acreage associated with the subject interests in which McMoRan owned rights to the related leases as of December 31, 2014.[(a)]

	Developed Gross Acres	Developed Net Acres	Undeveloped Gross Acres	Undeveloped Net Acres
Offshore (federal waters)	—	—	217,963	133,205
Onshore South Louisiana	9,000	6,480	91,113	48,986
Total as of December 31, 2014	9,000	6,480	309,076	182,191 [(b)]

(a) In addition, McMoRan controls interests in leases covering approximately 6,000 gross acres (5,900 net acres) associated with the subject interests.
(b) Includes 76,399 net acres that are scheduled to expire during 2015, for which carrying values associated with the subject interests were impaired during fourth-quarter 2014.

The following table reflects changes in oil and gas acreage (all of which is undeveloped) held or controlled by McMoRan and associated with the subject interests from December 31, 2013 to December 31, 2014.

	Gross Acres			Net Acres		
	Offshore	Onshore	Controlled by Options	Offshore	Onshore	Controlled by Options
Total as of December 31, 2013	228,739	57,079	49,705	144,284	28,206	35,772
Acquisitions	14,224 [(a)]	27,169 [(a)]	—	6,920 [(a)]	13,487 [(a)]	—
Options exercised/expired	—	24,780 [(b)]	(43,666) [(b)]	—	17,023 [(b)]	(29,895) [(b)]
Lease expirations and other	(25,000) [(c)]	(8,915) [(c)]	—	(17,999) [(c)]	(3,250) [(c)]	—
Total as of December 31, 2014	217,963	100,113	6,039	133,205	55,466	5,877

((a) Acquisition of additional acreage is primarily associated with the offshore Lafitte and England subject interests and the onshore Highlander and Tortuga subject interests.
(b) During the year ended December 31, 2014, McMoRan exercised options to acquire 24,780 gross (17,023 net) acres and allowed 18,886 gross (12,872 net) optioned acres to expire.
(c) Lease expirations and other is primarily related to the expiration of the leases associated with the offshore Barbosa, Blackbeard East and Queen Anne's Revenge subject interests and adjustments resulting from surveys and title examinations.

Oil and Gas Reserves. Reserve volumes attributable to the subject interests have been determined in accordance with the current regulations and guidelines established by the SEC, which require the use of an average price, calculated as the twelve-month average of the first-day-of-the-month historical reference price as adjusted for location and quality differentials, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions and the impact of derivatives. Reference prices for reserve determination are the West Texas Intermediate (WTI) spot price for crude oil and the Henry Hub spot price for natural gas. At December 31, 2014, reserve estimates were based on reference prices of $4.35 per thousand cubic feet (Mcf) and $94.99 per barrel. All of the oil and natural gas reserves attributable to the subject interests are located in the U.S.

Proved Reserves. All of the estimated proved oil and natural gas reserves at December 31, 2014, are based upon reserve reports prepared by the independent petroleum engineering firms of Netherland, Sewell & Associates, Inc. (NSAI) and Ryder Scott Company, L.P. (Ryder Scott). The scope and results of procedures employed by NSAI and Ryder Scott are summarized in letters that are filed as exhibits to this annual report on Form 10-K. For purposes of reserve estimation, McMoRan and its independent petroleum engineers used technical and economic data including well logs, geologic maps, seismic data, well test data, production data, historical price and cost

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information, and property ownership interests. These reserves have been estimated using deterministic methods. Standard engineering and geoscience methods were used, or a combination of methods, including performance analysis, volumetric analysis and analogy, which McMoRan and its independent petroleum engineers considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for undeveloped locations; such reserves are based on estimates of reserve volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. Because these estimates depend on many assumptions, any or all of which may differ substantially from actual results, reserve estimates may differ from the quantities of oil and natural gas that we ultimately recover.

Proved reserves represent 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. At December 31, 2014, estimated proved oil and natural gas reserves attributable to the subject interests totaled 2.1 Bcfe, of which 98 percent was comprised of natural gas.

	Natural Gas (MMcf)	Oil (MBbls)	Total (Bcfe)
Proved developed	1,384	—	1.4
Proved undeveloped	687	7	0.7
Total proved reserves	2,071	7	2.1

At December 31, 2014, proved undeveloped reserves represented 34 percent of proved reserves attributable to the subject interests. There have been no changes to proved undeveloped reserves during the year ended December 31, 2014, and none of the proved reserves have been classified as proved undeveloped for more than five years. All of the proved reserves are scheduled for development within five years. The Royalty Trust is not subject to development costs under the terms of the trust agreement.

The following table reflects the present value of estimated future net cash flows before income taxes from the production and sale of estimated proved reserves attributable to the subject interests reconciled to the standardized measure of discounted net cash flows (standardized measure) at December 31, 2014.

	Proved Reserves		
	Developed	Undeveloped	Total
Estimated undiscounted future net cash flows before income taxes	$ 5,295,200	$ 3,389,567	$ 8,684,767
Present value of estimated future net cash flows before income taxes (PV-10) [(a), (b)]	$ 4,266,500	$ 2,593,557	$ 6,860,057
Discounted future income taxes [(c)]			—
Standardized measure (See Note 8)			$ 6,860,057

(a) In accordance with SEC guidelines, estimates of future net cash flows from proved reserves and the present value thereof are made using the twelve-month average of the first-day-of-the-month historical reference prices as adjusted for location and quality differentials. Reference prices as of December 31, 2014, were $4.35 per Mcf of natural gas and $94.99 per barrel of oil. These prices are held constant throughout the life of the oil and gas properties, except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. In accordance with the guidelines, the average realized prices used in the Royalty Trust reserve report as of December 31, 2014, were $4.10 per Mcf of natural gas and $94.99 per barrel of oil. The Royalty Trust's reference prices are the Henry Hub spot price for natural gas and the WTI spot price for crude oil.

(b) The present value of estimated future net cash flows before income taxes (PV-10) is not considered a U.S. generally accepted accounting principle (GAAP) financial measure. The Royalty Trust believes that the PV-10 presentation is relevant and useful to its investors because it presents the discounted future net cash flows attributable to the subject interest's proved reserves. PV-10 is not a measure of financial or operating

performance under U.S. 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 U.S. GAAP (see Note 8).
(c) For tax reporting purposes, the Royalty Trust is considered a non taxable "pass-through" entity (see Note 4).

Refer to Note 8 for further discussion of proved reserves.

Internal Control and Qualifications of Third Party Engineers and Internal Staff. The technical personnel responsible for preparing the reserve estimates at NSAI and Ryder Scott meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Both NSAI and Ryder Scott are independent firms of petroleum engineers, geologists, geophysicists, and petrophysicists; neither firm owns an interest in McMoRan's properties associated with the subject interests nor are they employed on a contingent fee basis. McMoRan's internal reservoir engineering staff are led and overseen by its Vice President of Engineering, who has over 38 years of technical experience in petroleum engineering and reservoir evaluation and analysis. This individual directs the activities of its internal reservoir staff for the internal reserve estimation process and also provides the appropriate data to NSAI and Ryder Scott for the Royalty Trust's year-end oil and natural gas reserves estimation process.

Production and Productive Well Interests. As of December 31, 2014, none of the subject interests had any associated commercial production. As such, there were no productive oil or natural gas wells, or wells capable of production, associated with the subject interests as of December 31, 2014.

The onshore Highlander subject interest began commercial production on February 25, 2015. Prior to this date there had been no commercial production of hydrocarbons from any of the subject interests. Since its inception, the Royalty Trust has received no proceeds from oil and gas production related to the subject interests.

REGULATION

Although the Royalty Trust is not responsible for the activities, expenses, and obligations discussed in this section, such matters relate to McMoRan’s activities with respect to the subject interests.

General. McMoRan’s 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. McMoRan has obtained or timely applied for all material licenses, permits and other authorizations currently required for operations. 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.

Exploration, Production and Development. Among other things, federal and state level regulation of McMoRan’s 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. McMoRan’s 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, 2014, there are 46 offshore leases located in federal waters on the Gulf of Mexico’s outer continental shelf relating to the subject interests. McMoRan currently intends to allow 23 of such leases to expire during 2015 (See Note 3). Federal offshore leases are administered by the BOEM. These leases were obtained through competitive bidding, contain relatively standard terms and require compliance with detailed BOEM regulations, BSEE regulations and the Outer Continental Shelf Lands Act (OCSLA), each of which is 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 United States (U.S.) Coast Guard and the Environmental Protection Agency (EPA). 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/BOEM have regulations governing the plugging and abandonment of wells located offshore and the installation and removal of all fixed drilling and production facilities. BSEE/BOEM generally require 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. McMoRan is currently satisfying the supplemental bonding requirements of BSEE/BOEM by providing financial assurances. McMoRan's ongoing compliance with applicable BSEE/BOEM requirements will be subject to meeting certain financial and other criteria. Under some circumstances, BSEE/BOEM could require any operations on federal leases to be suspended or terminated. Any suspension or termination of operations related to the subject interests for a prolonged duration would likely have a material adverse effect on the Royalty Trust's future financial condition and results of operations.

State and Local Regulation of Drilling and Production. McMoRan also owns interests in properties located in state waters of Louisiana and onshore in South Louisiana. Louisiana regulates drilling and operating activities by requiring, among other things, drilling permits and bonds and reports concerning operations. The laws of Louisiana 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. McMoRan's operations are subject to numerous laws relating to environmental protection. These laws impose substantial penalties for any pollution resulting from McMoRan's operations. The Trustee has been advised by McMoRan that McMoRan believes that its operations comply with applicable laws, including environmental laws, in all material respects.

Solid Waste. McMoRan's 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 McMoRan currently operates are presently in the process of developing stricter disposal standards for nonhazardous waste. Changes in these standards may impact McMoRan's operations.

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 to occur 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, McMoRan may generate or arrange for the disposal of "hazardous substances" within the meaning of CERCLA or comparable state statutes in the course of its ordinary operations. Thus, McMoRan 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, McMoRan may be subject to cost recovery and to some other claims as a result of its operations.

Air. McMoRan’s 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 McMoRan's operations. Therefore, McMoRan may incur future capital expenditures to upgrade its air pollution control equipment.

Water. The Clean Water Act prohibits any discharge into waters of the U.S. 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 (Oil Pollution Act) 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 $133.65 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. McMoRan currently maintains insurance on its respective facilities to meet the financial assurance obligations under 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 McMoRan's exploration, development, and production operations and impose civil or criminal penalties for noncompliance.

EMPLOYEES

The Royalty Trust is a passive entity and has no employees. All administrative functions of the Royalty Trust are performed by the Trustee.

COMPETITION

The production and sale of oil and natural gas in the shallow waters on the Shelf of the Gulf of Mexico and onshore in South Louisiana is highly competitive, particularly with respect to hiring and retention of technical personnel, the acquisition of leases, interests and other properties, and access to drilling rigs and other services in such areas. McMoRan's competitors in these areas include major integrated oil and gas companies and numerous independent oil and gas companies, individual producers and operators.

Oil and natural gas compete with other forms of energy available to customers, primarily based on price. These alternate forms of energy include electricity, coal and fuel oils. Changes in the availability or price of oil, natural gas or other forms of energy, as well as business conditions, conservation, legislation, regulations and the ability to convert to alternate fuels and other forms of energy may affect the demand for oil and natural gas.
If and to the extent that the subject interests begin to produce in commercial quantities, future price fluctuations for oil and natural gas will directly affect the amount of distributions to Royalty Trust unitholders, if any, and will also affect estimates of reserves attributable to the overriding royalty interests and estimated and actual future net revenues of the Royalty Trust. Neither McMoRan nor the Royalty Trust can make reliable predictions of future oil and natural gas supply and demand or future product prices. For more information regarding risks associated with oil and gas production and commodity price fluctuations, see Part I, Item 1A. "Risk Factors" of this Form 10-K.
SEASONALITY

All of the Royalty Trust's assets are located in the U.S., where demand for natural gas is typically lower in summer than in the winter. Tropical storms and hurricanes, which are particularly common in the Gulf of Mexico and South Louisiana during the summer and early fall of each year, can damage or completely destroy drilling, production and treatment facilities, which can result in the interruption or permanent cessation of production from associated wells.

The Royalty Trust is not otherwise materially affected by seasonal factors.

TAX CONSIDERATIONS

Tax counsel to the special committee of the board of directors of MMR advised the Royalty Trust at the time of formation that, for U.S. federal income tax purposes, in its opinion, the Royalty Trust would be treated as a grantor trust and not as an unincorporated business entity. No ruling has been or will be requested from the IRS or another taxing authority.

As a grantor trust, the Royalty Trust is not subject to tax at the Royalty Trust level. Rather, the Royalty Trust unitholders are considered to own and receive the Royalty Trust's assets and income and are directly taxable thereon as though no trust were in existence. Under Treasury Regulations, the Royalty Trust is classified as a widely held fixed investment trust. Pursuant to a de minimis test provided for in the Treasury Regulations, the Royalty Trust is only required to report the amount of sales proceeds distributed to a Royalty Trust unitholder during the year with respect to a sale or disposition of a trust asset. In addition, the Treasury Regulations require the sharing of tax information among trustees and intermediaries that hold a trust interest on behalf of or for the account of a beneficial owner or any representative or agent of a trust interest holder of fixed investment trusts that are classified as widely held fixed investment trusts.

The widely held fixed investment trust reporting requirements provide for the dissemination of trust tax information by the trustee to intermediaries who are ultimately responsible for reporting the investor-specific information through Form 1099 to the investors and the IRS. Every trustee or intermediary that is required to file a Form 1099 for a Royalty Trust unitholder must furnish a written tax information statement that is in support of the amounts as reported on the applicable Form 1099 to the Royalty Trust unitholder. In compliance with the reporting requirements of the Treasury regulations for non-mortgage widely held fixed investment trusts and the dissemination of Royalty Trust tax reporting information, the Trustee provides a generic tax information reporting booklet which is intended to be used only to assist Royalty Trust unitholders in the preparation of their 2014 federal and state income tax returns. This tax information booklet can be obtained at http://gultu.investorhq.businesswire.com/. Any generic tax information provided by the Trustee is intended to be used only to assist Royalty Trust unitholders in the preparation of their U.S. federal and state income tax returns.

If the Royalty Trust were classified as a business entity, it would be taxable as a partnership unless it failed to meet certain qualifying income tests applicable to “publicly traded partnerships.” The income of the Royalty Trust is expected to meet such qualifying income tests. As a result, even if the Royalty Trust were considered to be a publicly traded partnership it should not be taxable as a corporation. The principal tax consequence of the Royalty Trust's possible categorization as a partnership rather than a grantor trust is that all Royalty Trust unitholders would be required to report their share of taxable income from the Royalty Trust on the accrual method of accounting regardless of their own method of accounting.

The Royalty Trust owns an overriding royalty interest burdening the subject interests, which are located in Louisiana and in federal waters offshore Louisiana. Tax counsel to the special committee of the board of directors of MMR advised the Royalty Trust at its formation that the Royalty Trust will be treated as a grantor trust and not as an unincorporated business entity for U.S. federal income tax purposes. If the Royalty Trust is treated as a grantor trust for U.S. federal income tax purposes, it would also be treated as a grantor trust for Louisiana income tax purposes. As a grantor trust, the Royalty Trust would not be subject to Louisiana income tax at the Royalty Trust level. Rather, for Louisiana individual income tax purposes, the Royalty Trust unitholders would be considered to own and receive the Royalty Trust’s assets and income and will be directly taxable thereon as though no trust were in existence. Consequently, individual Royalty Trust unitholders may be subject to Louisiana individual income tax on all or a portion of their shares of any Royalty Trust income. Individual Royalty Trust unitholders who are legal residents of Louisiana will be subject to Louisiana individual income tax on all of their shares of any Royalty Trust income. Individual Royalty Trust unitholders who are not legal residents of Louisiana generally will be subject to Louisiana individual income tax only on the portion of their shares of any Royalty Trust income that is sourced to Louisiana. For Louisiana individual income tax purposes, royalties from mineral properties are specifically sourced to the state where such property is located at the time the income is derived.

Individual Royalty Trust unitholders who are required to file Louisiana individual income tax returns and pay Louisiana individual income tax on all or a portion of their proportionate shares of any Royalty Trust income may be subject to penalties for failure to comply with such requirements. The highest marginal rates for the payment of Louisiana income taxes are 6% for individuals, trusts and estates, and 8% for corporations. Individual taxpayers are allowed a deduction for depletion in Louisiana. Louisiana currently does not require the Royalty Trust to withhold Louisiana individual income taxes from distributions made to non-resident Royalty Trust unitholders if the Royalty

Trust is treated as a grantor trust for U.S. federal income tax purposes. Individual Royalty Trust unitholders who are legal residents of a state other than Louisiana may be subject to state and local individual income taxes, if any, in their states of residence on their receipt of any income from the Royalty Trust.

WHERE YOU CAN FIND OTHER INFORMATION

The Royalty Trust maintains a website at http://gultu.investorhq.businesswire.com. The Royalty Trust’s filings under the Exchange Act are available through its website and are also available electronically from the website maintained by the SEC at http://www.sec.gov. In addition, the Royalty Trust will provide electronic and paper copies of its recent filings free of charge upon request to the Trustee.

Item 1A. Risk Factors

This Form 10-K contains “forward-looking statements.” Please refer to the section above entitled “Forward-Looking Statements” for more information.

The value of the royalty trust units is uncertain. As of March 12, 2015, only the onshore Highlander subject interest has achieved commercial production; the subject interests are exploration concepts and, other than the onshore Lineham Creek and onshore Highlander subject interests, do not have proved, probable or possible reserves assigned to them.

The Royalty Trust's only assets and sources of income are the overriding royalty interests burdening the subject interests. The overriding royalty interests entitle the Royalty Trust to receive a portion of the proceeds derived from the sale of hydrocarbons associated with the subject interests, if any. As of March 12, 2015, only the onshore Lineham Creek and Highlander subject interests have any reserves classified as proved, probable or possible, and only the onshore Highlander subject interest has achieved commercial production. Since its inception through March 12, 2015, the Royalty Trust has received no proceeds from oil and gas production related to the subject interests and there have been no cash distributions to Royalty Trust unitholders. With the exception of the onshore Highlander subject interest which is currently under development, the subject interests remain “exploration concepts” and further drilling and flow testing will be required to determine further commercial potential of the subject interests.

The Royalty Trust has no ability to direct or influence the exploration or development of the subject interests. In addition, neither FCX nor McMoRan are under any obligation to fund or to commit any resources to the exploration or development of the subject interests. McMoRan has informed the Trustee that, due to the sharp decline in oil prices during the fourth quarter of 2014, budgeted 2015 capital expenditures were reduced, near-term activities on all subject interests except for the onshore Highlander subject interests have been deferred, and McMoRan's leases on most of the subject interests will be allowed to expire during 2015 (See Note 3).

Oil and natural gas prices fluctuate due to a number of factors that are beyond the control of the Royalty Trust, FCX and McMoRan, and lower prices could reduce proceeds to the Royalty Trust and cash distributions, if any, to Royalty Trust unitholders.

Oil and gas prices fluctuate widely in response to relatively minor changes in supply, market uncertainty and a variety of additional factors that are beyond the control of FCX, McMoRan and the Royalty Trust. These factors include, among others:

- regional, domestic and foreign supply of, and demand for, oil and natural gas, as well as perceptions of supply of, and demand for, oil and natural gas;

- the price of foreign imports;

- U.S. and worldwide political and economic conditions;
- weather conditions and seasonal trends;
- anticipated future prices of oil and natural gas, alternative fuels and other commodities;

- technological advances affecting energy consumption and energy supply;
- the proximity, capacity, cost and availability of pipeline infrastructure, treating, transportation and refining capacity;
- natural disasters and other acts of force majeure;
- domestic and foreign governmental regulations and taxation;
- energy conservation and environmental measures; and
- the price and availability of alternative fuels.

During the second half of 2014, oil prices declined significantly. After averaging $100.84 per barrel in the first half of 2014, West Texas Intermediate (WTI) crude oil prices averaged $85.22 per barrel for the second half of 2014 and declined to a low of $52.44 per barrel on December 31, 2014. During first-quarter 2015, oil prices have further declined and WTI crude oil prices were $47.05 per barrel on March 12, 2015. To the extent there is production of oil and gas associated with the overriding royalty interests, the royalties that the Royalty Trust may receive from its share of production will be reduced as a result of lower oil and gas prices. As a result, future distributions, if any, from the Royalty Trust to its unitholders could be reduced or discontinued. In addition, lower oil and gas prices reduce the likelihood that the subject interests will be developed or that any oil and gas discovered will be economic to produce. Lower oil and natural gas prices could make it more likely that additional leases in the undeveloped acreage will expire at the end of their respective primary terms as a result of the failure to establish production from such leasehold acreage in commercially paying quantities prior to such date. The sharp decline in oil prices during the fourth quarter of 2014 was a contributing factor to the impairment charges totaling $231.7 million recorded for the year ended December 31, 2014. Refer to Note 3 for further discussion of these impairment charges. The volatility of energy prices reduces the accuracy of estimates of future cash distributions to the Royalty Trust unitholders and could affect the value of the royalty trust units.

The subject interests target Inboard Lower Tertiary/Cretaceous formations in the shallow waters on the Shelf of the Gulf of Mexico and onshore in South Louisiana, which have greater risks and costs associated with their exploration and development than conventional Gulf of Mexico prospects.

McMoRan's Inboard Lower Tertiary/Cretaceous exploration prospects target formations below the salt weld on the Shelf of the Gulf of Mexico and onshore in South Louisiana. These targets have not traditionally been the subject of exploratory activity in these regions, and, therefore, little direct comparative data is available. To date, only the onshore Highlander subject interest has achieved commercial production of hydrocarbons from Inboard Lower Tertiary/Cretaceous reservoirs in these areas. The lack of comparative data and the limitations of diagnostic tools operating in the extreme temperatures and pressures encountered at these depths make it difficult to predict reservoir quality and well performance of these formations. It is also significantly more expensive and risky to drill and complete wells in these formations than at more conventional depths. Major contributors to such increased costs and risks include far higher temperatures and pressures encountered down hole, longer drilling times and the cost and extended procurement time related to the specialized equipment required to drill and complete these types of wells.

The Royalty Trust unitholders may experience fluctuations in the market price and volume of the trading market for the royalty trust units, and we may not be able to comply with the continued listing standards of The NASDAQ Capital Market.

The Royalty Trust unitholders may experience fluctuations in the market price and volume of the trading market for the royalty trust units for many reasons, including, without limitation:

- the failure of the subject interests to produce hydrocarbons;
- decisions by McMoRan to delay or not to pursue the exploration or development of some or all of the subject interests;
- reasons unrelated to operational performance, such as reports by industry analysts, investor perceptions, or announcements by competitors regarding their own performance;

- legal or regulatory changes that could impact the business of McMoRan; and
- general economic, securities markets and industry conditions.

Fluctuations in the volume of the trading market may have a negative effect on the market price for the royalty trust units. Accordingly, Royalty Trust unitholders may not be able to realize a fair price when they determine to sell their royalty trust units, or may have to hold them for a substantial period of time until the market for the royalty trust units improves, if it does at all. FCX has a call right with respect to the outstanding royalty trust units at $10 per royalty trust unit, provided that the call right may not be exercised prior to June 3, 2018. This call right could impose a ceiling on the price of the royalty trust units. See Part I, Items 1. and 2. “Business and Properties - The Royalty Trust - The Royalty Trust Agreement - FCX Call Rights” of this Form 10-K. In addition, Royalty Trust unitholders may incur brokerage charges in connection with the resale of the royalty trust units, which in some cases could exceed the proceeds realized from the resale of their royalty trust units.

Additionally, if the Royalty Trust is not able to meet the continued listing requirements of The NASDAQ Capital Market (the NASDAQ), which require, among other things, that the high trading price of the royalty trust units not fall below $1 per royalty trust unit for 30 consecutive trading days, the royalty trust units may be delisted. The high trading price of the royalty trust units on March 12, 2015 was $0.95. If the royalty trust units were delisted from the NASDAQ, the royalty trust units would be traded over-the-counter, more commonly known as OTC. OTC transactions involve risks in addition to those associated with transactions in securities traded on the NASDAQ. Many OTC securities trade less frequently and in smaller volumes than securities traded on the NASDAQ. Accordingly, the royalty trust units would be less liquid, and the value of the royalty trust units could further decline.

The tax treatment of the royalty trust units is uncertain.

Although the tax treatment of overriding royalty interests in specified developed wells that have been drilled is well developed, the law is less developed in the area of overriding royalty interests on exploration prospects that are not classified as proved, probable or possible reserves and are undeveloped wells that may be drilled in the future. As a result, there is uncertainty as to the proper tax treatment of the overriding royalty interests held by the Royalty Trust, and counsel is unable to express any opinion as to the proper tax treatment as either a mineral royalty interest or a production payment. Based on the state of facts as of the date hereof, the Royalty Trust intends to treat the royalty trust units as mineral royalty interests for U.S. federal income tax purposes. However, no ruling has been requested from the IRS regarding the proper treatment of the royalty trust units; therefore, the IRS may assert, or a court may sustain the IRS in asserting, that the royalty trust units should be treated as “production payments” that are debt instruments for U.S. federal income tax purposes subject to the Treasury Regulations applicable to contingent payment debt instruments.

Royalty Trust unitholders should consult their tax advisors as to the specific tax consequences of the ownership and disposition of the royalty trust units, including the applicability and effect of U.S. federal, state, local and foreign income and other tax laws in light of their particular circumstances.

The Royalty Trust has not requested a ruling from the IRS regarding the tax treatment of ownership of the royalty trust units. If the IRS were to determine (and be sustained in that determination) that the Royalty Trust is not a “grantor trust” for federal income tax purposes, or that the overriding royalty interests are not properly treated as mineral royalty interests for U.S. federal income tax purposes, the Royalty Trust unitholders may receive different and potentially less advantageous tax treatment.

If the Royalty Trust were not treated as a grantor trust for U.S. federal income tax purposes, the Royalty Trust should be treated as a partnership for such purposes. Although the Royalty Trust would not become subject to U.S. federal income taxation at the entity level as a result of treatment as a partnership, and items of income, gain, loss and deduction would flow through to the Royalty Trust unitholders, the Royalty Trust's tax reporting requirements would be more complex and costly to implement and maintain, and any distributions to Royalty Trust unitholders could be reduced as a result.

If the overriding royalty interests were not treated as a mineral royalty interest, the amount, timing and character of income, gain, or loss in respect of an investment in the Royalty Trust could be affected.

The Royalty Trust has not requested a ruling from the IRS regarding these tax questions. The IRS could challenge these positions on audit, and such challenges could be sustained by a court.

Among the changes included in President Obama's Budget Proposal for Fiscal Year 2016 is the elimination of the ability of publicly traded partnerships that derive at least 90 percent of their gross income from activities relating to fossil fuels to be classified as a partnership for U.S. federal income tax purposes, which would result in such partnerships being classified as corporations for such purposes. If the Royalty Trust were not treated as a grantor trust for U.S. federal income tax purposes and President Obama's proposal is enacted, the Royalty Trust may be treated as a corporation for U.S. federal income tax purposes.

No assurance can be given with respect to the availability and extent of percentage depletion deductions to the Royalty Trust unitholders for any taxable year.

Payments out of production that are received by a Royalty Trust unitholder in respect of a mineral royalty interest for U.S. federal income tax purposes are taxable under current law as ordinary income subject to an allowance for cost or percentage depletion in respect of such income. The rules with respect to this depletion allowance are complex and must be computed separately by each Royalty Trust unitholder and not by the Royalty Trust for each oil or gas property. As a result, no assurance can be given, and counsel is unable to express any opinion, with respect to the availability or extent of percentage depletion deductions to the Royalty Trust unitholders for any taxable year.

The Royalty Trust encourages Royalty Trust unitholders to consult their own tax advisors to determine whether and to what extent percentage depletion would be available to them.

Certain U.S. federal income tax preferences currently available with respect to oil and natural gas production may be eliminated as a result of future legislation.

Among the changes included in President Obama's Budget Proposal for Fiscal Year 2016 is the elimination of certain key U.S. federal income tax preferences relating to oil and natural gas exploration and production. The President's budget proposes to eliminate certain tax preferences applicable to taxpayers engaged in the exploration or production of natural resources. Specifically, the budget proposes to repeal the deduction for percentage depletion with respect to wells, including interests such as the overriding royalty interests, in which case only cost depletion would be available.

Royalty Trust unitholders will be required to pay taxes on their pro-rata share of the taxable income attributable to the assets of the Royalty Trust even if they do not receive any cash distributions from the Royalty Trust.

Because the holders of royalty trust units will be taxed directly on their pro-rata share of the taxable income attributable to the assets of the Royalty Trust and such taxable income could be different in amount than the cash the Royalty Trust distributes, Royalty Trust unitholders will be required to pay any U.S. federal income taxes and, in some cases, state and local income taxes on such taxable income even if they receive no cash distributions from the Royalty Trust. Royalty Trust unitholders may not receive cash distributions from the Royalty Trust equal to their pro-rata share of the taxable income attributable to the assets of the Royalty Trust or even equal to the actual tax liability that results from that income.

As a consequence of special reporting rules, Royalty Trust unitholders may not be able to recognize income/claim losses realized by the Royalty Trust until the unitholders dispose of Royalty Trust units.

If the Royalty Trust satisfies the general de minimis test prescribed by the IRS, the Royalty Trust will only be required to report, with respect to sales or dispositions of trust assets, the amount of sales proceeds distributed to a Royalty

Trust unitholder during the year. Reporting under the de minimis exception will leave unitholders with inadequate information to be able to fully report the result of the sales and dispositions falling under the de minimis threshold in a given year. The reason for the de minimis exception is that the IRS and the Treasury Department believe that if a widely held fixed investment trust such as the Royalty Trust sells or disposes of assets infrequently, although there may be some deferral of gains and losses if sales and dispositions are not fully reported, the deferral is acceptable, in light of the burden of fully and accurately reporting the sales and dispositions.

Production risks can adversely affect distributions from the Royalty Trust.

The occurrence of drilling, production or transportation accidents at any of the subject interests could reduce or eliminate Royalty Trust distributions, if any. While the Royalty Trust, as the owner of the overriding royalty interests, should not be responsible for the costs associated with any such accidents, any such accidents may result in the loss of a productive well and associated reserves or interruption of production.

In the event McMoRan needs but is unable to procure or maintain a suspension of operations (SOO) granted by the BSEE with respect to certain of its Inboard Lower Tertiary/Cretaceous gas play acreage associated with the subject interests, McMoRan's ability to exploit some of the potentially valuable acreage associated with its Inboard Lower Tertiary/Cretaceous gas play and the subject interests could be adversely affected.

McMoRan's interests in the offshore leases located in federal waters on the Gulf of Mexico's outer continental shelf are administered by the BOEM and the BSEE and require compliance with BOEM and BSEE regulations and the OCSLA. Under the OCSLA, McMoRan is expected 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 initial term of a lease, McMoRan's ability to drill, rework, or produce a particular well in paying quantities may, despite McMoRan's diligent efforts, be delayed. In this case, McMoRan has the ability to request that the BSEE extend the lease term beyond its scheduled expiration or termination. Provided McMoRan's 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 McMoRan 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.

While it is not uncommon for companies in the oil and gas industry to continue to operate leases under an SOO granted by the BSEE, in the event (1) McMoRan fails to satisfy any obligations or conditions set forth in an SOO with respect to a particular lease, (2) McMoRan is 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, McMoRan's ability to exploit some of the potentially valuable acreage associated with its Inboard Lower Tertiary/Cretaceous gas play and the subject interests could be adversely affected.

Approximately 134,000 net acres owned or controlled (through options to lease) by McMoRan associated with the subject interests are scheduled to expire in 2015, 2016 and 2017. McMoRan has informed the Trustee that it does not plan to further develop the offshore Davy Jones, Blackbeard West and Blackbeard West #3 subject interests and does not plan to commence development of the offshore Barataria, Drake, Hook, Captain Blood, Bonnet and Calico Jack subject interests, prior to their respective lease expirations in 2015. Additionally, McMoRan has informed the Trustee that it does not plan to develop the offshore Davy Jones West and Hurricane subject interests (See Note 3).

The Royalty Trust is vulnerable to risks associated with operations in the Gulf of Mexico and onshore in South Louisiana because the subject interests are located exclusively in those areas.

These risks include:

- tropical storms and hurricanes, which are particularly common in the Gulf of Mexico and South Louisiana during the summer and early fall of each year, and which can damage or completely destroy drilling, production and treatment facilities, which can result in the interruption or permanent cessation of production from associated wells;

- 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, including those relating to other operators and/or other geographical areas.

These exposures in the Gulf of Mexico and onshore in South Louisiana could have a material adverse effect on the subject interests, on the Royalty Trust's results of operations and financial condition, and on the market price of the Royalty Trust units.

The Royalty Trust is entirely dependent on FCX for funding unless and until such time as it receives income from any production on the subject interests, and even when the Royalty Trust receives income from production on the subject interests, any such income may be insufficient to cover the Royalty Trust's administrative expenses.

Although the onshore Highlander subject interest began commercial production on February 25, 2015, the Royalty Trust has not yet received royalty payments. Therefore, it must rely on FCX for funding of its administrative expenses. Pursuant to the royalty trust agreement, FCX has agreed to pay annual trust expenses of the Royalty Trust up to a maximum amount of $350,000, with no right of repayment or interest due, to the extent the Royalty Trust lacks sufficient funds to pay administrative expenses. During each of the years ended December 31, 2014 and 2013, FCX contributed $350,000 to the Royalty Trust with respect to this arrangement. In addition to such annual contributions, FCX has agreed to lend money, on an unsecured, interest-free basis, to the Royalty Trust to fund the Royalty Trust's ordinary administrative expenses as set forth in the royalty trust agreement. During the years ended December 31, 2014 and 2013, FCX loaned $200,000 and $450,000, respectively, to the Royalty Trust under this arrangement, none of which has been repaid as of December 31, 2014. If the Trustee borrows funds, whether from FCX or from any other source, to cover expenses or liabilities, the Royalty Trust unitholders will not receive distributions until the borrowed funds are repaid.

Pursuant to the royalty trust agreement, FCX agreed to provide and maintain a $1.0 million stand-by reserve account or an equivalent letter of credit for the benefit of the Royalty Trust to enable the Trustee to draw on such reserve account or letter of credit to pay obligations of the Royalty Trust in the event that it has inadequate funds to pay its obligations at any time. Currently, with the consent of the Trustee, FCX may reduce the reserve account or substitute a letter of credit with a different face amount for the original letter of credit or any substitute letter of credit. In connection with this arrangement, FCX has provided $1.0 million in the form of a reserve fund cash account to the Royalty Trust.

FCX's interests and the interests of the Royalty Trust unitholders may not always be aligned.

Because FCX has interests in oil and gas properties not included in the subject interests, FCX's interests and the interests of the Royalty Trust unitholders are not completely aligned. For example, in setting budgets for development and production expenditures for FCX's properties, including the subject interests, FCX may make decisions that could adversely affect future production from the subject interests. For example, McMoRan has informed the Trustee that, due to the sharp decline in oil prices during the fourth quarter of 2014, budgeted 2015 capital expenditures were reduced and near-term activities on all subject interests except for the onshore Highlander subject interests have been deferred (See Note 3). Moreover, FCX could decide to sell, not drill or abandon some or all of the subject interests, and any such decision would not be in the best interests of the Royalty Trust unitholders. As described in this report, McMoRan does not plan to drill or conduct operational activities on thirteen subject interests prior to their lease expiration dates in 2015.

FCX may transfer the subject interests.

FCX may at any time transfer all or part of the subject interests. The Royalty Trust unitholders are not entitled to vote on any transfer, and the Royalty Trust will not receive any proceeds from the transfer of the subject interests. Following any such transfer, the subject interests would continue to be subject to the overriding royalty interests, but the net proceeds from the transferred subject interests would be calculated separately and paid by the transferee. The transferee would be responsible for all of FCX's obligations relating to the overriding royalty interests on the portion of the subject interests transferred, and FCX would have no continuing obligation to the Royalty Trust for those subject interests.

The Royalty Trust is limited in duration, may be dissolved upon certain events and the royalty trust units are subject to call features after June 3, 2018.

The Royalty Trust will dissolve on the earlier of (i) June 3, 2033, (ii) the sale of all of the overriding royalty interests, (iii) the election of the Trustee following its resignation for cause (as more fully described in the royalty trust agreement), (iv) a vote of the holders of 80% (which after June 3, 2018, shall be reduced to 66 %) or more of the outstanding royalty trust units held by persons other than FCX or any of its affiliates, at a duly called meeting of the Royalty Trust unitholders at which a quorum is present, or (v) the exercise by FCX of the right to call all of the royalty trust units as described in the next paragraph. The overriding royalty interests terminate upon the termination of the Royalty Trust, other than in certain limited circumstances where the Royalty Trust has been permitted to transfer the overriding royalty interests to a third party pursuant to the terms of the royalty trust agreement (in which case the overriding royalty interests may extend through June 3, 2033).

FCX has a call right with respect to the outstanding royalty trust units at $10 per royalty trust unit, provided that the call right may not be exercised prior to June 3, 2018. In addition, at any time after June 3, 2018, if the royalty trust units are then listed for trading or admitted for quotation on a national securities exchange or any quotation system and the volume weighted average price per royalty trust unit is equal to $0.25 or less for the immediately preceding consecutive nine-month period, FCX may purchase all, but not less than all, of the outstanding royalty trust units at a price of $0.25 per royalty trust unit so long as FCX tenders payment within 30 days of such nine-month period.

The Royalty Trust is passive in nature and neither the Royalty Trust nor the Royalty Trust unitholders have any ability to influence FCX or McMoRan or to control the development or operation of the subject interests.
The royalty trust units are a passive investment that entitle the Royalty Trust unitholders only to receive cash distributions, if any, from the overriding royalty interests. Royalty Trust unitholders have no voting rights with respect to FCX or McMoRan and, therefore, have no managerial, contractual or other ability to influence their activities or the development or operations of the subject interests. Additionally, neither FCX nor McMoRan are under any obligation to fund or to commit any resources to the exploration or development of the subject interests.

FCX may sell royalty trust units in the public or private markets, and any such sales would be highly likely to have a material adverse effect on the trading price of the royalty trust units.
FCX holds an aggregate of 62,285,438 royalty trust units, representing approximately 27.1% of the outstanding royalty trust units. FCX may sell royalty trust units in the public or private markets. Any such sales would be highly likely to have a material adverse effect on the trading price of the royalty trust units. A small number of other unitholders also hold significant percentages of the outstanding royalty trust units, and sales by such holders could also have a material adverse effect on the trading price of the royalty trust units. See Part III, Item 12. "Security Ownership of Certain Beneficial Owners and Management and Related Royalty Trust Unitholder Matters" of this Form 10-K.
The Royalty Trust is managed by a Trustee who cannot be replaced except by a majority vote of the Royalty Trust unitholders, which may make it difficult for Royalty Trust unitholders to remove or replace the Trustee.
The affairs of the Royalty Trust are managed by the Trustee. The voting rights of Royalty Trust unitholders are more limited than those of stockholders of most public corporations. For example, there is no requirement for the Royalty Trust to hold annual meetings of Royalty Trust unitholders or for an annual or other periodic re-election of the Trustee. The Royalty Trust does not intend to hold annual meetings of Royalty Trust unitholders. The royalty trust agreement provides that the Trustee may only be removed by the holders of a majority of the royalty trust units outstanding. As a result, it would be difficult for public Royalty Trust unitholders to remove or replace the Trustee without the cooperation of FCX so long as it holds a significant percentage of the total royalty trust units.
Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

There are currently no pending legal proceedings to which the Royalty Trust is a party.

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Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Royalty Trust Units, Related Royalty Trust Unitholder Matters and Issuer Purchases of Royalty Trust Units

The royalty trust units began trading on The NASDAQ Capital Market (the NASDAQ) under the symbol “GULTU” on June 2, 2014. Prior to June 2, 2014 and beginning October 10, 2013, the royalty trust units were quoted on the OTCQX tier of the OTC markets (the OTCQX) under the symbol “GULTU”. Prior to October 10, 2013 and beginning June 4, 2013, the royalty trust units were quoted on the Over-the-Counter Bulletin Board (the OTCBB). Prior to June 4, 2013, there was no established public trading market for the royalty trust units. For information regarding fluctuations in the market price and trading volume of the royalty trust units, see Part I, Item 1A. "Risk Factors" of this Form 10-K.
The following table shows the high and low sales/bid prices, as applicable, per royalty trust unit as reported on the NASDAQ, the OTCQX and the OTCBB for the periods indicated. Quotations on the OTCQX and the OTCBB reflect bid and ask quotations, may reflect inter-dealer prices, without retail markup, markdown or commission, and may not represent actual transactions. There have been no distributions to Royalty Trust unitholders to date. For more information on future distributions to Royalty Trust unitholders, see Part I, Item 1A. "Risk Factors" and Part II, Items 7. and 7A. "Trustee's Discussion and Analysis of Financial Condition and Results of Operations and Quantitative and Qualitative Disclosures About Market Risk - Liquidity and Capital Resources" of this Form 10-K.

		2014				2013		
		High		Low		High		Low
First Quarter	$	3.33	$	2.05		n/a		n/a
Second Quarter		3.24		2.64	$	2.50	$	1.75
Third Quarter		2.93		1.56		2.35		2.00
Fourth Quarter		2.00		0.90		2.44		2.01

As of February 28, 2015 there were 230,172,696 royalty trust units outstanding and 5,583 Royalty Trust unitholders of record.

Recent Sales of Unregistered Securities and Royalty Trust Unitholder Matters
There were no equity securities sold by the Royalty Trust during the year ended December 31, 2014. At December 31, 2014, FCX, through its wholly owned subsidiary McMoRan, held 62,285,438 royalty trust units. FCX is currently the largest holder of royalty trust units with approximately 27.1% of the outstanding royalty trust units.

Securities Authorized for Issuance Under Equity Compensation Plans
None.

Purchases of Royalty Trust Units by the Issuer and Affiliated Purchasers
None.

Item 6. Selected Financial Data

The following table sets forth selected audited historical financial data of the Royalty Trust for the years ended December 31, 2014 and 2013 and for the period December 18, 2012 (inception) through December 31, 2012. The historical information shown in the table below may not be indicative of the Royalty Trust's future results. You should read the information below together with Part II, Items 7. and 7A. "Trustee's Discussion and Analysis of Financial Condition and Results of Operations and Quantitative and Qualitative Disclosures About Market Risk" and Part II, Item 8. "Financial Statements and Supplementary Data" of this Form 10-K. References to "Notes" refer to Notes to Financial Statements located in Part II, Item 8. "Financial Statements and Supplementary Data" of this Form 10-K.

	2014	2013	2012
Financial Data			
Periods Ended December 31:			
Royalty income	$ —	$ —	$ —
Interest income	1	4	—
Administrative expenses	(603,380)	(606,163)	—
Administrative expenses in excess of income	(603,379)	(606,159)	—
Distributable income	$ —	$ —	$ —
Distributable income per royalty trust unit	$ —	$ —	$ —
At December 31:			
Overriding royalty interests in subject interests	$ 168,567,700 [a]	$ 400,300,341	$ —
Total assets	$ 169,708,214	$ 401,494,215	$ 10
Trust corpus	$ 168,058,172	$ 400,044,192	$ 10
Royalty trust units outstanding	230,172,696	230,172,696	—

a. Impairment charges totaling $231.7 million, representing the carrying values associated with thirteen of the subject interests, were recorded for the year ended December 31, 2014. McMoRan has informed the Trustee that due to the sharp decline in oil prices during the fourth quarter of 2014, budgeted 2015 capital expenditures were reduced and future activities on all subject interests except for the onshore Highlander subject interest have been deferred. As a result of these factors and well-specific data, McMoRan does not plan to drill or conduct operational activities on the thirteen subject interests prior to their lease expiration dates which required an impairment of their carrying values. In the event on or before December 5, 2017, McMoRan acquires a leasehold interest covering the same area and block covered by a terminated lease, or acquires additional leasehold interests associated with the subject interests, such newly acquired leasehold interests shall become subject interests.

Items 7. and 7A. Trustee'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 Part II, Item 8. "Financial Statements and Supplementary Data" and Part I, Items 1. and 2. "Business and Properties" of this Form 10-K. The results of operations reported and summarized below are not necessarily indicative of future operating results. Unless otherwise specified, all references to "Notes" refer to Notes to Financial Statements located in Part II, Item 8. "Financial Statements and Supplementary Data" of this Form 10-K. A glossary of definitions for some of the oil and gas industry terms used in this Form 10-K is provided beginning on page 53. Additionally, please refer to the section above entitled "Forward-Looking Statements." The information below has been furnished to the Trustee by Freeport-McMoRan Inc. (FCX) and FCX's indirect wholly owned subsidiary, McMoRan Oil & Gas LLC (McMoRan).

On June 3, 2013, FCX and McMoRan Exploration Co. (MMR) completed the transactions contemplated by the Agreement and Plan of Merger, dated as of December 5, 2012 (the merger agreement), by and among MMR, FCX, and INAVN Corp., a Delaware corporation and indirect wholly owned subsidiary of FCX (Merger Sub). Pursuant to the merger agreement, Merger Sub merged with and into MMR, with MMR surviving the merger as an indirect wholly owned subsidiary of FCX (the merger).

FCX's portfolio of oil and gas assets is held through its wholly owned subsidiary, FCX Oil & Gas Inc. (FM O&G). As a result of the merger, MMR and McMoRan (MMR's wholly owned operating subsidiary) are both wholly owned subsidiaries of FM O&G.

The Royalty Trust was created as contemplated by the merger agreement, and is a statutory trust created by FCX under the Delaware Statutory Trust Act pursuant to a trust agreement entered into on December 18, 2012 (inception), by and among FCX, as depositor, Wilmington Trust, National Association, as Delaware trustee, and certain officers of FCX, as regular trustees. On May 29, 2013, Wilmington Trust, National Association, was replaced by BNY Trust of Delaware, as Delaware trustee (the Delaware Trustee), through an action of the depositor. Effective June 3, 2013, the regular trustees were replaced by The Bank of New York Mellon Trust Company, N.A., a national banking association, as trustee (the Trustee).

The Royalty Trust was created to hold a 5% gross overriding royalty interest (collectively, the overriding royalty interests) in future production from each of McMoRan's shallow water Inboard Lower Tertiary/Cretaceous exploration prospects located on the Shelf of the Gulf of Mexico and onshore in South Louisiana that existed as of December 5, 2012, the date of the merger agreement (collectively, the subject interests). The subject interests were "carved out" of the mineral interests that were acquired by FCX pursuant to the merger and were not considered part of FCX's purchase consideration of MMR. McMoRan owns less than 100% of the working interest associated with each of the subject interests.

In connection with the merger, on June 3, 2013, (1) FCX, as depositor, McMoRan, as grantor, the Trustee and the Delaware Trustee, entered into the amended and restated royalty trust agreement to govern the Royalty Trust and the respective rights and obligations of FCX, the Trustee, the Delaware Trustee, and the Royalty Trust unitholders with respect to the Royalty Trust (the royalty trust agreement); and (2) McMoRan, as grantor, and the Royalty Trust, as grantee, entered into the master conveyance of overriding royalty interest (the master conveyance) pursuant to which McMoRan conveyed to the Royalty Trust the overriding royalty interests in future production from the subject interests. Other than (a) its formation, (b) its receipt of contributions and loans from FCX for administrative and other expenses as provided for in the royalty trust agreement, (c) its payment of such administrative and other expenses and (d) its receipt of the conveyance of the overriding royalty interests from McMoRan pursuant to the master conveyance, the Royalty Trust has not conducted any activities. The Trustee has no involvement with, control over, or responsibility for, any aspect of any operations on or relating to the subject interests.

Since 2008, McMoRan's Inboard Lower Tertiary/Cretaceous drilling activities (below the salt weld, i.e., the listric fault) have confirmed McMoRan's belief relating to its geologic model and the highly prospective nature of this emerging geologic trend. McMoRan believes that data from eight Inboard Lower Tertiary/Cretaceous wells drilled to date indicate the presence of geologic formations that are analogous to productive formations in the Deepwater Gulf of Mexico and onshore in the Gulf Coast region. McMoRan has informed the Trustee that due to the sharp decline in oil prices during the fourth quarter of 2014, budgeted 2015 capital expenditures were reduced and near-term activities on all subject interests except for the onshore Highlander subject interests have been deferred (See Note 3). Each of these eight wells was included in the subject interests, along with additional exploration prospects that will also be burdened by the overriding royalty interests. The onshore Highlander subject interest began commercial production on February 25, 2015. Prior to this date there had been no commercial production of hydrocarbons from any of the subject interests.

Currently, only the onshore Lineham Creek and Highlander subject interests have any reserves classified as proved, probable or possible and only the onshore Highlander subject interest has achieved commercial production. The Royalty Trust has no ability to direct or influence the exploration or development of the subject interests. In addition, neither FCX nor McMoRan are under any obligation to fund or to commit any resources to the exploration or development of the subject interests. To the extent that McMoRan does not fund the exploration and development of the subject interests, or if for any other reason sufficient production from the subject interests in commercial quantities is not achieved or maintained, Royalty Trust unitholders will not realize any value from their investment in the royalty trust units.

North American Natural Gas and Crude Oil Market Prices

Market prices for natural gas and crude oil can fluctuate significantly. During the period from January 2005 through March 12, 2015, the New York Mercantile Exchange (NYMEX) natural gas price fluctuated from a low of $1.90 per million British thermal units (MMBtu) in 2012 to a high of $15.78 per MMBtu in 2005 and the West Texas Intermediate (WTI) crude oil price ranged from a low of $32.40 per barrel in 2008 to a high of $147.27 per barrel in 2008. During the second half of 2014, oil prices declined significantly. After averaging $100.84 per barrel in the first half of 2014, WTI crude oil prices averaged $85.22 per barrel for the second half of 2014 and declined to a low of $52.44 per barrel on December 31, 2014. During first-quarter 2015, oil prices have further declined and WTI crude oil prices were $47.05 per barrel on March 12, 2015. Crude oil and natural gas prices are affected by numerous factors beyond McMoRan's control as described further in Part I, Item 1A. "Risk Factors" of this Form 10-K. The following graph presents the NYMEX natural gas prices and the WTI crude oil prices from January 2005 through March 12, 2015.

OPERATIONAL ACTIVITIES

Oil and Gas Activities
For additional information regarding McMoRan’s current oil and gas activities in relation to the subject interests, see Part I, Items 1. and 2. “Business and Properties - The Subject Interests - Exploratory and Development Drilling” and Part I, Item 1A. “Risk Factors” of this Form 10-K.

Production
As of December 31, 2014, none of the subject interests had any commercial production and there were no productive oil or natural gas wells, or wells capable of production. As such, the Royalty Trust has received no proceeds from oil and gas production related to the subject interests. The onshore Highlander subject interest began commercial production on February 25, 2015. Prior to this date there had been no commercial production of hydrocarbons from any of the subject interests.

Acreage Position
For information regarding McMoRan’s acreage position, see Part I, Items 1. and 2. “Business and Properties - The Subject Interests - Acreage” of this Form 10-K.

RESULTS OF OPERATIONS

As of December 31, 2014, only the onshore Lineham Creek and Highlander subject interests had any reserves classified as proved, probable or possible and none of the subject interests had any associated commercial production. The onshore Highlander subject interest began commercial production on February 25, 2015. To date, the Royalty Trust has received no proceeds from oil and gas production from the subject interests since its inception. For the years ended December 31, 2014 and 2013, the Royalty Trust paid administrative expenses of $603,380 and $606,163, respectively, which consisted primarily of audit, legal and trustee expenses incurred in connection with the administration of the Royalty Trust. The Royalty Trust paid no administrative expenses for the year ended December 31, 2012.

LIQUIDITY AND CAPITAL RESOURCES

Although the onshore Highlander subject interest began commercial production on February 25, 2015, the Royalty Trust has not received any royalty payments to date. Pursuant to the royalty trust agreement, FCX has agreed to pay annual trust expenses up to a maximum amount of $350,000, with no right of repayment or interest due, to the extent the Royalty Trust lacks sufficient funds to pay administrative expenses. During each of the years ended December 31, 2014 and 2013, FCX contributed $350,000 to the Royalty Trust with respect to this arrangement. In addition to such annual contributions, FCX has agreed to lend money, on an unsecured, interest-free basis, to the Royalty Trust to fund the Royalty Trust's ordinary administrative expenses as set forth in the royalty trust agreement. During the years ended December 31, 2014 and 2013, FCX loaned $200,000 and $450,000, respectively, to the Royalty Trust under this arrangement, none of which has been repaid as of December 31, 2014.

Pursuant to the royalty trust agreement, FCX agreed to provide and maintain a $1.0 million stand-by reserve account or an equivalent letter of credit for the benefit of the Royalty Trust to enable the Trustee to draw on the reserve account or letter of credit to pay obligations of the Royalty Trust in the event that it has inadequate funds to pay its obligations at any time. Currently, with the consent of the Trustee, FCX may reduce the reserve account or substitute a letter of credit with a different face amount for the original letter of credit or any substitute letter of credit. In connection with this arrangement, FCX has provided $1.0 million in the form of a reserve fund cash account to the Royalty Trust. The Royalty Trust has not drawn any funds from the reserve account, and FCX has not requested a reduction of such reserve account.

Currently, the Royalty Trust has no source of liquidity or capital resources other than mandatory annual contributions, any loans and the required standby reserve account or letter of credit from FCX. Any material adverse change in FCX's financial condition or results of operations could materially and adversely affect the Royalty Trust and the underlying royalty trust units.

Once the Royalty Trust begins receiving royalty payments, on a quarterly basis the Trustee will determine the amount of funds available for distribution to the Royalty Trust unitholders. Available funds will equal the excess cash received by the Royalty Trust from the overriding royalty interests and other sources during that quarter over the Royalty Trust’s liabilities for that quarter. In any event, no distributions will be made until such time as the Trustee receives cash proceeds from the overriding royalty interests. Additionally, to the extent that the Trustee has borrowed funds, whether from FCX or from any other source, to cover expenses or liabilities, the Royalty Trust unitholders will not receive distributions until the borrowed funds are repaid. Available funds will be further reduced by any cash the Trustee determines to hold as a reserve against future liabilities. The Trustee shall establish a cash reserve equal to such amount. Royalty Trust unitholders that own their royalty trust units on the close of business on the record date for each calendar quarter will receive a pro-rata distribution of the amount of the cash available for distribution generally 10 business days after the quarterly record date.

OFF-BALANCE SHEET ARRANGEMENTS

The Royalty Trust has no off-balance sheet arrangements. The Royalty Trust has not guaranteed the debt of any other party, nor does the Royalty Trust have any other arrangements or relationships with other entities that could potentially result in unconsolidated debt, losses or contingent obligations.

CONTRACTUAL OBLIGATIONS

A summary of the Royalty Trust's contractual obligations as of December 31, 2014 is provided in the following table:

	Payments Due by Year				
	Total	2015	2016 to 2017	2018 to 2019	After 2019
	(in thousands)				
Trustee Administrative Fee [a]	(a)	$200	$400	$400	(a)
Total [a]	(a)	$200	$400	$400	(a)

(a) The Trustee Administrative Fee compensates the Trustee for performance of the Trustee's duties and responsibilities related to the administration of the Royalty Trust, including usual and customary ministerial duties, preparation and filing of all Securities and Exchange Commission (SEC) reports and press releases, record keeping, document compliance, coordination with the transfer agent as it relates to distributions and other related duties and maintenance of accounts on various systems. The trust agreement requires the Trustee to be paid the sum of $150,000 per year until the first year in which the Royalty Trust receives any payment pursuant to the conveyances of the overriding royalty interests, at which time such sum shall be increased to $200,000 per year. The onshore Highlander subject interest began commercial production on February 25, 2015. Accordingly, it is anticipated that the Trustee will be paid $200,000 per year beginning in 2015.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The financial statements of the Royalty Trust are prepared on the modified cash basis of accounting and are not intended to present the Royalty Trust's financial position and results of operations in conformity with U.S. generally accepted accounting principles (GAAP). This other comprehensive basis of accounting corresponds to the accounting permitted for royalty trusts by the SEC. There has been no distributable income paid or due to the Royalty Trust unitholders from inception through December 31, 2014.

The Royalty Trust's operating cash and reserve fund cash amounts represent deposits in highly liquid short-term U.S. Treasury money market funds.

The initial amount recorded for the overriding royalty interests in the subject interests conveyed to the Royalty Trust was derived from the actual number of royalty trust units issued, the closing price of $16.75 per share of MMR's common stock on June 3, 2013, the closing date of the merger, reduced by the per share cash consideration received by MMR shareholders resulting in the related implied initial value of the royalty trust units of $400.3 million. Application of income tax requirements resulted in different values for tax reporting purposes for the Royalty Trust unitholders.

The value of the Royalty Trust's overriding royalty interests in the subject interests (defined in Note 2) will be amortized using the units of production method based on estimated proved reserves, on an individual subject interest basis, once production has been achieved for the respective subject interests. Such non-cash amortization will be charged directly to the Trust Corpus, and will not affect distributable cash or the determination of distributable cash per royalty trust unit.

The Royalty Trust evaluates the carrying values of the overriding royalty interests in the subject interests for impairment if conditions indicate that potential uncertainty exists regarding the Royalty Trust's ability to recover its recorded amounts related to the overriding royalty interests. Indications of potential impairment with respect to the overriding royalty interests can include, among other things, subject interest lease expirations, reductions in estimated reserve quantities or resource potential, changes in estimated future oil and gas prices, exploration costs, and/or drilling plans, and other matters that arise that could negatively impact the carrying values of the overriding royalty interests. When the overriding royalty interests are deemed impaired, the related impairment amounts are charged to the Trust Corpus in the period such impairment is determined.

Impairment charges totaling $231.7 million, representing the carrying value associated with thirteen of the subject interests, were recorded for the year ended December 31, 2014. McMoRan has informed the Trustee that due to the sharp decline in oil prices during the fourth quarter of 2014, budgeted 2015 capital expenditures were reduced and near-term activities on all subject interests except for the onshore Highlander subject interest have been deferred. As a result of these factors and well-specific data, McMoRan does not plan to drill or conduct operational activities on the thirteen subject interests prior to their lease expiration dates, which required an impairment of their carrying values. In the event on or before December 5, 2017, McMoRan acquires a leasehold interest covering the same area and block covered by a terminated lease, or acquires additional leasehold interests associated with the subject interests, such newly acquired leasehold interests shall become subject interests.

DISCLOSURES ABOUT MARKET RISKS

The Royalty Trust's most significant credit risk relates to adverse changes in FCX's financial condition or results of operations. Although the onshore Highlander subject interest began commercial production on February 25, 2015, the Royalty Trust has not received any royalty payments to date. Therefore, it must rely on FCX for funding of its administrative expenses. FCX has agreed to pay annual trust expenses up to a maximum amount of $350,000, with no right of repayment or interest due, to the extent the Royalty Trust lacks sufficient funds to pay administrative expenses. During each of the years ended December 31, 2014 and 2013, FCX contributed $350,000 to the Royalty Trust with respect to this arrangement.

In addition to such annual contributions, FCX has agreed to lend money, on an unsecured, interest-free basis, to the Royalty Trust to fund the Royalty Trust's ordinary administrative expenses as set forth in the royalty trust agreement. During the years ended December 31, 2014 and 2013, FCX loaned $200,000 and $450,000, respectively, to the Royalty Trust under this arrangement, none of which has been repaid as of December 31, 2014. Any material adverse change in FCX's financial condition or results of operations could materially and adversely affect the Royalty Trust and the underlying royalty trust units.

FCX has also agreed to provide and maintain a $1.0 million stand-by reserve account or an equivalent letter of credit for the benefit of the Royalty Trust to enable the Trustee to draw on such reserve account or letter of credit to pay obligations of the Royalty Trust in the event that it has inadequate funds to pay its obligations at any time. Currently, with the consent of the Trustee, FCX may reduce the reserve account or substitute a letter of credit with a different face amount for the original letter of credit or any substitute letter of credit. In connection with this arrangement, FCX has provided $1.0 million in the form of a reserve fund cash account to the Royalty Trust. The Royalty Trust has not drawn any funds from the reserve account, and FCX has not requested a reduction of such reserve account.

The Royalty Trust is a passive entity and, except for the Royalty Trust’s ability to borrow from FCX as described above, the Royalty Trust is prohibited from engaging in loan transactions. The Royalty Trust periodically holds short-term investments acquired with funds held by the Royalty Trust for the payment of its administrative and other expenses. Because of the short-term nature of these investments and limitations on the types of investments which may be held by the Royalty Trust, the Royalty Trust is not subject to any material interest rate risk. The Royalty Trust does not engage in transactions in foreign currencies which could expose the Royalty Trust unitholders to foreign currency related market risk nor does the Royalty Trust engage in any other financial derivative transactions.

The Royalty Trust's most significant market risk relates to the prices received for oil and natural gas production. The revenues will be derived from the subject interests and will depend substantially on prevailing natural gas prices, and to a lesser extent oil prices. As a result, commodity prices also will affect the amount of cash flow, if any, available for distribution to the Royalty Trust unitholders. Lower oil and natural gas prices may also reduce the amount of oil and natural gas, if any, that McMoRan or the third-party operators will be able to economically produce and may reduce the likelihood that the subject interests will be developed.

During 2014, the NYMEX natural gas price fluctuated from a low of $2.88 per million British thermal units (MMBtu) to a high of $6.49 per MMBtu and the WTI crude oil price ranged from a low of $52.44 per barrel to a high of $107.73 per barrel. During the second half of 2014, oil prices declined significantly. After averaging $100.84 per barrel in the first half of 2014, WTI crude oil prices averaged $85.22 per barrel for the second half of 2014 and declined to a low of $52.44 per barrel on December 31, 2014. During first-quarter 2015, oil prices have further declined and WTI crude oil prices were $47.05 per barrel on March 12, 2015.

Any future production will be subject to uncertainties, many of which will be beyond McMoRan’s control, including the timing and flow rates associated with the initial production from discoveries, weather-related factors, shut-in or recompletion activities on any of the subject interests’ related 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 estimated annualized sales volumes. For more information regarding risks associated with oil and gas production and commodity price fluctuations, see Part I, Item 1A. "Risk Factors" of this Form 10-K.

NEW ACCOUNTING STANDARDS

The Royalty Trust does not expect recently issued accounting standards to have a significant impact on its future financial statements and disclosures.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

TO THE TRUSTEE AND HOLDERS OF ROYALTY TRUST UNITS
OF GULF COAST ULTRA DEEP ROYALTY TRUST:

We have audited Gulf Coast Ultra Deep Royalty Trust's (the Royalty Trust) internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). The Bank of New York Mellon Trust Company, N.A., as Trustee of the Royalty Trust, is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on the Royalty Trust’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.

The Royalty Trust'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 the modified cash basis of accounting, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States. The Royalty Trust'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 Royalty Trust; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with the modified cash basis of accounting, and that receipts and expenditures of the trust are being made only in accordance with authorizations of the Trustee of the Royalty Trust; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Royalty Trust'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, the Royalty Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the accompanying statements of assets, liabilities and trust corpus of the Royalty Trust as of December 31, 2014 and 2013, and the related statements of distributable income and changes in trust corpus for the years ended December 31, 2014 and 2013 and the period from December 18, 2012 (inception) through December 31, 2012, and our report dated March 16, 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana
March 16, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

TO THE TRUSTEE AND HOLDERS OF ROYALTY TRUST UNITS
OF GULF COAST ULTRA DEEP ROYALTY TRUST:

We have audited the accompanying statements of assets, liabilities and trust corpus of Gulf Coast Ultra Deep Royalty Trust (the Royalty Trust) as of December 31, 2014 and 2013, and the related statements of distributable income and changes in trust corpus for the years ended December 31, 2014 and 2013 and the period from December 18, 2012 (inception) through December 31, 2012. These financial statements are the responsibility of The Bank of New York Mellon Trust Company, N.A., as the Royalty Trust's trustee (the Trustee). 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 the Trustee, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As described in Note 1 to the financial statements, these financial statements were prepared on the modified cash basis of accounting, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States.

In our opinion, the financial statements referred to above present fairly, in all material respects, the assets, liabilities and trust corpus of the Royalty Trust at December 31, 2014 and 2013, and the distributable income and changes in trust corpus for the years ended December 31, 2014 and 2013 and the period from December 18, 2012 (inception) through December 31, 2012, in conformity with the modified cash basis of accounting described in Note 1.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Royalty Trust's internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated March 16, 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana
March 16, 2015

GULF COAST ULTRA DEEP ROYALTY TRUST
STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

	December 31, 2014	2013
ASSETS		
Operating cash	$ 140,472	$ 193,851
Reserve fund cash	1,000,042	1,000,023
Overriding royalty interests in subject interests	168,567,700	400,300,341
Total assets	$ 169,708,214	$ 401,494,215
LIABILITIES AND TRUST CORPUS		
Reserve fund liability	$ 1,000,042	$ 1,000,023
Loan payable to Freeport-McMoRan Inc. (FCX)	650,000	450,000
Trust corpus (230,172,696 royalty trust units authorized, issued and outstanding as of December 31, 2014 and 2013)	168,058,172	400,044,192
Total liabilities and trust corpus	$ 169,708,214	$ 401,494,215

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

GULF COAST ULTRA DEEP ROYALTY TRUST
STATEMENTS OF DISTRIBUTABLE INCOME

	Years Ended December 31, 2014	2013	Period from December 18, 2012 (inception) through December 31, 2012
Royalty income	$ —	$ —	$ —
Interest income	1	4	—
Administrative expenses	(603,380)	(606,163)	—
Administrative expenses in excess of income	$ (603,379)	$ (606,159)	$ —
Distributable income	$ —	$ —	$ —
Distributable income per royalty trust unit	$ —	$ —	$ —
Royalty trust units outstanding at end of period	230,172,696	230,172,696	—

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

GULF COAST ULTRA DEEP ROYALTY TRUST
STATEMENTS OF CHANGES IN TRUST CORPUS

	Years Ended December 31, 2014	2013	Period from December 18, 2012 (inception) through December 31, 2012
Trust corpus, beginning of period	$ 400,044,192	$ 10	$ —
Trust contributions	350,000	350,000	10
Impairment of subject interests	(231,732,641)	—	—
Administrative expenses in excess of income	(603,379)	(606,159)	—
Overriding royalty interests in subject interests	—	400,300,341	—
Trust corpus, end of period	$ 168,058,172	$ 400,044,192	$ 10

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

GULF COAST ULTRA DEEP ROYALTY TRUST
NOTES TO FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES
The financial statements of Gulf Coast Ultra Deep Royalty Trust (the Royalty Trust) are prepared on the modified cash basis of accounting and are not intended to present the Royalty Trust's financial position and results of operations in conformity with United States (U.S.) generally accepted accounting principles (GAAP). This other comprehensive basis of accounting corresponds to the accounting permitted for royalty trusts by the U.S. Securities and Exchange Commission (SEC), as specified by Staff Accounting Bulletin Topic 12:E, Financial Statements of Royalty Trusts. There has been no distributable income paid or due to the Royalty Trust unitholders from inception (defined in Note 2) through December 31, 2014.

The Royalty Trust's operating cash and reserve fund cash amounts represent deposits in highly liquid short-term U.S. Treasury money market funds.

As required for financial reporting purposes, the initial amount recorded for the overriding royalty interests in the subject interests conveyed to the Royalty Trust was derived from the actual number of royalty trust units issued, the closing price of $16.75 per share of McMoRan Exploration Co.'s (MMR) common stock on June 3, 2013, the closing date of the merger (defined in Note 2), reduced by the per share cash consideration received by MMR shareholders resulting in the related implied initial value of the royalty trust units of $400.3 million. Application of income tax requirements resulted in different values for tax reporting purposes for the Royalty Trust unitholders. For more information on the conveyance of the overriding royalty interests, see Note 2.
The value of the Royalty Trust's overriding royalty interests in the subject interests (each defined in Note 2) will be amortized using the units of production method based on estimated proved reserves, on an individual subject interest basis, once production has been achieved for the respective subject interests. Such non-cash amortization will be charged directly to the Trust Corpus, and will not affect distributable cash or the determination of distributable cash per royalty trust unit.
The Royalty Trust evaluates the carrying values of the overriding royalty interests in the subject interests for impairment if conditions indicate that potential uncertainty exists regarding the Royalty Trust's ability to recover its recorded amounts related to the overriding royalty interests. Indications of potential impairment with respect to the overriding royalty interests can include, among other things, subject interest lease expirations, reductions in estimated reserve quantities or resource potential, changes in estimated future oil and gas prices, exploration costs, and/or drilling plans, and other matters that arise that could negatively impact the carrying values of the overriding royalty interests. When the overriding royalty interests are deemed impaired, the related impairment amounts are recorded as a reduction to the overriding royalty interest with an offsetting reduction to the Trust Corpus in the period such impairment is determined.
Impairment charges totaling $231.7 million, representing the carrying value associated with thirteen of the subject interests, were recorded for the year ended December 31, 2014. McMoRan Oil & Gas LLC (McMoRan, MMR's wholly owned subsidiary) has informed the Trustee that due to the sharp decline in oil prices during the fourth quarter of 2014, budgeted 2015 capital expenditures were reduced and near-term activities on all subject interests except for the onshore Highlander subject interest have been deferred. As a result of these factors and well-specific data, McMoRan does not plan to drill or conduct operational activities on the thirteen subject interests prior to their lease expiration dates, which required an impairment of their carrying values. In the event on or before December 5, 2017, McMoRan acquires a leasehold interest covering the same area and block covered by a terminated lease, or acquires additional leasehold interests associated with the subject interests, such newly acquired leasehold interests shall become subject interests.

2. FORMATION OF THE ROYALTY TRUST

On June 3, 2013, Freeport-McMoRan Inc. (FCX) and MMR completed the transactions contemplated by the Agreement and Plan of Merger, dated as of December 5, 2012 (the merger agreement), by and among MMR, FCX, and INAVN Corp., a Delaware corporation and indirect wholly owned subsidiary of FCX (Merger Sub). Pursuant to the merger agreement, Merger Sub merged with and into MMR, with MMR surviving the merger as an indirect wholly owned subsidiary of FCX (the merger).

FCX's portfolio of oil and gas assets is held through its wholly owned subsidiary, FCX Oil & Gas Inc. (FM O&G). As a result of the merger, MMR and McMoRan are both wholly owned subsidiaries of FM O&G.

The Royalty Trust was created as contemplated by the merger agreement, and is a statutory trust created by FCX under the Delaware Statutory Trust Act pursuant to a trust agreement entered into on December 18, 2012 (inception), by and among FCX, as depositor, Wilmington Trust, National Association, as Delaware trustee, and certain officers of FCX, as regular trustees. On May 29, 2013, Wilmington Trust, National Association, was replaced by BNY Trust of Delaware, as Delaware trustee (the Delaware Trustee), through an action of the depositor. Effective June 3, 2013, the regular trustees were replaced by The Bank of New York Mellon Trust Company, N.A., a national banking association, as trustee (the Trustee).

The Royalty Trust was created to hold a 5% gross overriding royalty interest (collectively, the overriding royalty interests) in future production from each of McMoRan's shallow water Inboard Lower Tertiary/Cretaceous exploration prospects located on the Shelf of the Gulf of Mexico and onshore in South Louisiana that existed as of December 5, 2012, the date of the merger agreement (collectively, the subject interests). The subject interests were "carved out" of the mineral interests that were acquired by FCX pursuant to the merger and were not considered part of FCX's purchase consideration of MMR. McMoRan owns less than 100% of the working interest associated with each of the subject interests.

In connection with the merger, on June 3, 2013, (1) FCX, as depositor, McMoRan, as grantor, the Trustee and the Delaware Trustee, entered into the amended and restated royalty trust agreement to govern the Royalty Trust and the respective rights and obligations of FCX, the Trustee, the Delaware Trustee, and the Royalty Trust unitholders with respect to the Royalty Trust (the royalty trust agreement); and (2) McMoRan, as grantor, and the Royalty Trust, as grantee, entered into the master conveyance of overriding royalty interest (the master conveyance) pursuant to which McMoRan conveyed to the Royalty Trust the overriding royalty interests in future production from the subject interests. Other than (a) its formation, (b) its receipt of contributions and loans from FCX for administrative and other expenses as provided for in the royalty trust agreement, (c) its payment of such administrative and other expenses, and (d) its receipt of the conveyance of the overriding royalty interests from McMoRan pursuant to the master conveyance, the Royalty Trust has not conducted any activities.

3. OVERRIDING ROYALTY INTERESTS

The royalty trust units represent beneficial interests in the Royalty Trust, which holds a 5% gross overriding royalty interest in future production from each of the subject interests during the life of the Royalty Trust. An "overriding" royalty interest in general represents a non-operating interest in an oil and gas property that provides the owner a specified share of production without any related operating expenses or development costs and is carved out of an oil and gas lessee's working or cost-bearing interest under the lease. In contrast, a "working" or "cost-bearing" interest in general represents an operating interest in an oil and gas property that provides the owner a specified share of production that is subject to all production expenses and development costs. An owner of a working or cost-bearing interest, subject to the terms of an applicable operating agreement, generally has the right to participate in the selection of a prospect, drilling location or drilling contractor, to propose the drilling of a well, to determine the timing and sequence of drilling operations, to commence or shut down production, to take over operations, or to share in any operating decision. An owner of an overriding royalty interest in general has none of the rights described in the preceding sentence, and neither the Royalty Trust nor the Royalty Trust unitholders have any such rights.

The subject interests consist of 20 specified shallow water Inboard Lower Tertiary/Cretaceous prospects (which have target depths generally greater than 18,000 feet total vertical depth) located on the Shelf of the Gulf of Mexico and onshore in South Louisiana, one of which is under development and the rest of which are exploration prospects. The offshore subject interests consist of the following exploration prospects: (1) Barataria; (2) Barbosa; (3) Blackbeard East; (4) Blackbeard West; (5) Blackbeard West #3; (6) Bonnet; (7) Calico Jack; (8) Captain Blood; (9) Davy Jones; (10) Davy Jones West; (11) Drake; (12) England; (13) Hook; (14) Hurricane; (15) Lafitte; (16) Morgan; and (17) Queen Anne's Revenge. The onshore subject interests consist of (1) Highlander; (2) Lineham Creek; and (3) Tortuga. With the exception of the onshore Highlander subject interest, which is currently under development, the onshore subject interests are currently exploration prospects. McMoRan does not own 100% of the estimated working interest associated with any of the subject interests. The overriding royalty interests in future production from the subject interests burden all of McMoRan's leasehold interests associated with such prospects as of December 5, 2012, and will burden any leasehold interests associated with such prospects which are acquired by McMoRan on or before December 5, 2017, up to the estimated working interests reflected in the table below (subject to McMoRan's right to dispose of a portion of the working interests to a percentage not less than the estimated working interests reflected in the table below). Each of the overriding royalty interests has been, or will be, proportionately reduced based on McMoRan's working interest to equal the product of 5% multiplied by a fraction, the numerator of which is the working interest held by McMoRan and its affiliates associated with the applicable subject interest (subject to a cap equal to McMoRan's estimated working interest (equal to the working interest McMoRan owns or expects to acquire and as reflected in the table below) associated with each subject interest, on a prospect by prospect basis) and the denominator of which is 100%.

As of December 5, 2012, the date of the merger agreement, the subject interests comprised all of McMoRan's Inboard Lower Tertiary/Cretaceous exploration prospects. Additional Inboard Lower Tertiary/Cretaceous exploration prospects developed by McMoRan (other than those reflected below) will not be included in the subject interests. As of December 31, 2014, McMoRan had acquired working interests in additional Inboard Lower Tertiary/Cretaceous exploration prospects that are not part of the subject interests.

Impairment charges totaling $231.7 million, representing the carrying value associated with thirteen of the subject interests, were recorded for the year ended December 31, 2014. McMoRan has informed the Trustee that due to the sharp decline in oil prices during the fourth quarter of 2014, budgeted 2015 capital expenditures were reduced and near-term activities on all subject interests except for the onshore Highlander subject interest have been deferred. As a result of these factors and well-specific data, McMoRan does not plan to drill or conduct operational activities on the thirteen subject interests prior to their lease expiration dates, which required an impairment of their carrying values. In the event on or before December 5, 2017, McMoRan acquires a leasehold interest covering the same area and block covered by a terminated lease, or acquires additional leasehold interests associated with the subject interests, such newly acquired leasehold interests shall become subject interests.

As of December 31, 2014, only the onshore Lineham Creek and Highlander subject interests had any reserves classified as proved, probable or possible and none of the subject interests had any associated commercial production. The onshore Highlander subject interest began commercial production on February 25, 2015. Approximately 2.1 Bcfe of estimated proved reserves related to the onshore Lineham Creek and Highlander subject interests are currently deemed attributable to the applicable overriding royalty interest proportionately reduced to reflect McMoRan's estimated working interest.

Information regarding McMoRan's estimated working interest and the Royalty Trust's estimated overriding royalty interest for each subject interest as of December 31, 2014 is set forth below.

Subject Interest	McMoRan's Estimated Working Interest Related to the Subject Interests	Operator	Royalty Trust's Estimated Overriding Royalty Interest (5% proportionately reduced to reflect the Estimated Working Interest)
Davy Jones [(a)]	63.4%	McMoRan	3.17%
Blackbeard East [(b)]	—	McMoRan	—
Lafitte [(c)]	72%	McMoRan	3.6%
Blackbeard West [(d)]	69.4%	McMoRan	3.47%
England [(e)]	36%	Chevron	1.8%
Barbosa [(f)]	—	McMoRan	—
Morgan [(g)]	—	McMoRan	—
Barataria [(h)]	72%	McMoRan	3.6%
Blackbeard West #3 [(d)]	69.4%	McMoRan	3.47%
Drake [(h)]	72%	McMoRan	3.6%
Davy Jones West [(i)]	36%	McMoRan	1.8%
Hurricane [(i)]	72%	McMoRan	3.6%
Hook [(h)]	72%	McMoRan	3.6%
Captain Blood [(h)]	72%	McMoRan	3.6%
Bonnet [(h)]	72%	McMoRan	3.6%
Queen Anne's Revenge [(j)]	—	McMoRan	—
Calico Jack [(h)]	36%	McMoRan	1.8%
Highlander	72%	McMoRan	3.6%
Lineham Creek	36%	Chevron	1.8%
Tortuga	72%	McMoRan	3.6%

(a) McMoRan has informed the Trustee that it does not plan to further develop the offshore Davy Jones subject interest prior to its third-quarter 2015 lease expiration. As such, an impairment charge of $26.9 million, representing the carrying value associated with the Davy Jones subject interest, was recorded during fourth quarter 2014 (See Note 1).

(b) In January 2015, McMoRan requested from the BSEE that its then pending request for a revised Suspension of Production (SOP) for the Blackbeard East unit be withdrawn, which effectively relinquished McMoRan's lease rights to the Blackbeard East unit as of December 31, 2014. As such, an impairment charge of $11.5 million, representing the carrying value associated with the offshore Blackbeard East subject interest, was recorded during fourth quarter 2014 (See Note 1). In the event on or before December 5, 2017, McMoRan acquires a leasehold interest covering the same area and block covered by the terminated lease, or acquires additional leasehold interests associated with the Blackbeard East subject interest, such newly acquired leasehold interests shall become part of the Blackbeard East subject interest, and if this were to occur, it is expected that McMoRan would hold an approximate 72% working interest in such acquired/reacquired leases, equating to an estimated overriding royalty interest of 3.6% to be held by the Royalty Trust.

(c) In June 2013, McMoRan relinquished its previously-held lease rights to the Lafitte prospect, and in June 2014, McMoRan received notice from the BOEM that its bid for the lease rights to Eugene Island 223 (associated with the offshore Lafitte subject interest) was accepted. McMoRan's rights to this reacquired lease became effective August 1, 2014, and such lease is now subject to the overriding royalty interests held by the Royalty Trust.

(d) McMoRan has informed the Trustee that it does not plan to further develop the Blackbeard West unit prior to its second-quarter 2015 lease expiration. As such, impairment charges totaling $24.9 million, representing the carrying value associated with the offshore Blackbeard West and Blackbeard West #3 subject interests, were recorded during fourth quarter 2014 (See Note 1).

(e) In June 2014, McMoRan received notice from the BOEM that its bids for the lease rights to Vermillion 17, 38 and 39 (associated with the offshore England subject interest) were accepted. McMoRan's rights to these leases became effective July 1, 2014, and such leases are now subject to the overriding royalty interests held by the Royalty Trust.

(f) McMoRan's rights to the Barbosa lease expired on June 30, 2014. During first-quarter 2014, an impairment charge of $28.6 million, representing the carrying value associated with the offshore Barbosa subject interest, was recorded as drilling activities were not expected to occur on this subject interest prior to its lease expiration date (See Note 1). In the event on or before December 5, 2017, McMoRan acquires a leasehold interest covering the same area and block covered by the terminated lease, or acquires additional leasehold interests associated with the Barbosa subject interest, such newly acquired leasehold interests shall become part of the Barbosa subject interest, and if this were to occur, it is expected that McMoRan would hold an approximate 72% working interest in such acquired/reacquired leases, equating to an estimated overriding royalty interest of 3.6% to be held by the Royalty Trust.

(g) McMoRan's rights to the Morgan lease expired on May 31, 2013. In the event on or before December 5, 2017, McMoRan acquires a leasehold interest covering the same area and block covered by the terminated lease, or acquires additional leasehold interests associated with the offshore Morgan subject interest, such newly acquired leasehold interests shall become part of the Morgan subject interest, and if this were to occur, it is expected that McMoRan would hold an approximate 72% working interest in such acquired/reacquired leases, equating to an estimated overriding royalty interest of 3.6% to be held by the Royalty Trust.

(h) McMoRan has informed the Trustee that it does not plan to develop the offshore Barataria, Drake, Hook, Captain Blood, Bonnet and Calico Jack subject interests prior to their 2015 lease expiration dates. As such, impairment charges totaling $119.9 million, representing the carrying value associated with these subject interests, were recorded during fourth quarter 2014 (See Note 1).

(i) McMoRan has informed the Trustee that it does not plan to develop the offshore Davy Jones West and Hurricane subject interests. As such, impairment charges totaling $19.9 million, representing the carrying value associated with these subject interests, were recorded during fourth quarter 2014 (See Note 1).

(j) McMoRan's rights to the leases associated with the offshore Queen Anne's Revenge subject interest expired on December 31, 2014. In the event on or before December 5, 2017, McMoRan acquires one or more leasehold interests covering the same area and blocks covered by the terminated leases, or acquires additional leasehold interests associated with the Queen Anne's Revenge subject interest, such newly acquired leasehold interests shall become part of the Queen Anne's Revenge subject interest, and if this were to occur, it is expected that McMoRan would hold an approximate 72% working interest in such acquired/reacquired leases, equating to an estimated overriding royalty interest of 3.6% to be held by the Royalty Trust.

The Royalty Trust has no ability to influence the exploration or development of the subject interests. In addition, neither FCX nor McMoRan are under any obligation to fund or to commit any other resources to the exploration or development of the subject interests. Further, FCX and McMoRan each has the right to elect not to participate in drilling or other operations conducted by other working interest owners with respect to the subject interests.

The Royalty Trust will dissolve on the earlier of (i) June 3, 2033, (ii) the sale of all of the overriding royalty interests, (iii) the election by the Trustee following its resignation for cause (as more fully described in the royalty trust agreement), (iv) a vote of the holders of 80% (which after June 3, 2018, shall be reduced to 66 %) or more of the outstanding royalty trust units held by persons other than FCX or any of its affiliates, at a duly called meeting of the Royalty Trust unitholders at which a quorum is present, or (v) the exercise by FCX of the right to call all of the royalty trust units as described in the next paragraph. The overriding royalty interests terminate upon the termination of the Royalty Trust, other than in certain limited circumstances where the Royalty Trust has been permitted to transfer the overriding royalty interests to a third party pursuant to the terms of the royalty trust agreement (in which case the overriding royalty interests may extend through June 3, 2033).

FCX has a call right with respect to the outstanding royalty trust units at $10 per royalty trust unit, provided that the call right may not be exercised prior to June 3, 2018. In addition, at any time after June 3, 2018, if the royalty trust units are then listed for trading or admitted for quotation on a national securities exchange or any quotation system and the volume weighted average price per royalty trust unit is equal to $0.25 or less for the immediately preceding consecutive nine-month period, FCX may purchase all, but not less than all, of the outstanding royalty trust units at a price of $0.25 per royalty trust unit so long as FCX tenders payment within 30 days of such nine-month period.

4. INCOME TAXES
Tax counsel to the special committee of the board of directors of MMR advised the Royalty Trust at the time of formation that, for U.S. federal income tax purposes, in its opinion, the Royalty Trust will be treated as a grantor trust and not as an unincorporated business entity. No ruling has been or will be requested from the Internal Revenue Service (IRS) or another taxing authority. As a grantor trust, the Royalty Trust will not be subject to tax at the Royalty Trust level. Rather, the Royalty Trust unitholders will be considered to own and receive the Royalty Trust's assets and income and will be directly taxable thereon as though no trust were in existence. Under Treasury Regulations, the Royalty Trust is classified as a widely held fixed investment trust. Those Treasury Regulations require the sharing of tax information among trustees and intermediaries that hold a trust interest on behalf of or for the account of a beneficial owner or any representative or agent of a trust interest holder of fixed investment trusts that are classified as widely held fixed investment trusts. These reporting requirements provide for the dissemination of trust tax information by the trustee to intermediaries who are ultimately responsible for reporting the investor-specific information through Form 1099 to the investors and the IRS. Every trustee or intermediary that is required to file a Form 1099 for a trust unitholder must furnish a written tax information statement that is in support of the amounts as reported on the applicable Form 1099 to the trust unitholder. Any generic tax information provided by the Trustee of the Royalty Trust is intended to be used only to assist Royalty Trust unitholders in the preparation of their U.S. federal and state income tax returns.

5. RELATED PARTY TRANSACTIONS
Funding of Administrative Expenses. Pursuant to the royalty trust agreement, FCX has agreed to pay annual trust expenses up to a maximum amount of $350,000, with no right of repayment or interest due, to the extent the Royalty Trust lacks sufficient funds to pay administrative expenses. During each of the years ended December 31, 2014 and 2013, FCX contributed $350,000 to the Royalty Trust with respect to this arrangement. In addition to such annual contributions, FCX has agreed to lend money, on an unsecured, interest-free basis, to the Royalty Trust to fund the Royalty Trust's ordinary administrative expenses as set forth in the royalty trust agreement. During the years ended December 31, 2014 and 2013, FCX loaned $200,000 and $450,000, respectively, to the Royalty Trust under this arrangement, none of which has been repaid as of December 31, 2014.

Pursuant to the royalty trust agreement, FCX agreed to provide and maintain a $1.0 million stand-by reserve account or an equivalent letter of credit for the benefit of the Royalty Trust to enable the Trustee to draw on such reserve account or letter of credit to pay obligations of the Royalty Trust in the event that it has inadequate funds to pay its obligations at any time. Currently, with the consent of the Trustee, FCX may reduce the reserve account or substitute a letter of credit with a different face amount for the original letter of credit or any substitute letter of credit. In connection with this arrangement, FCX has provided $1.0 million in the form of a reserve fund cash account to the Royalty Trust, which amount is reflected as reserve fund cash with a corresponding reserve fund liability in the accompanying Statements of Assets, Liabilities and Trust Corpus. The Royalty Trust has not drawn any funds from the reserve account, and FCX has not requested a reduction of such reserve account. For additional information regarding the royalty trust agreement, see Note 2.

Compensation of the Trustee. The Trustee is paid the sum of $150,000 per year until the first year in which the Royalty Trust receives any payment pursuant to the conveyances of the overriding royalty interests, at which time such sum will be increased to $200,000 per year. The onshore Highlander subject interest began commercial production on February 25, 2015. Accordingly, it is anticipated that the Trustee will be paid $200,000 per year beginning in 2015. Additionally, the Trustee receives reimbursement for its reasonable out-of-pocket expenses incurred in connection with the administration of the Royalty Trust. The Trustee’s compensation is paid out of the Royalty Trust’s assets. The Trustee has a lien on the Royalty Trust’s assets to secure payment of its compensation and any indemnification expenses and other amounts to which it is entitled under the royalty trust agreement.

Royalty Trust Units Held by FCX. At December 31, 2014, the Royalty Trust had 230,172,696 royalty trust units outstanding and FCX, through its indirect wholly owned subsidiary McMoRan, held 62,285,438 royalty trust units (or 27.1% of the outstanding royalty trust units). FCX is currently the largest holder of outstanding royalty trust units.

6. CONTINGENCIES
Litigation. There are currently no pending legal proceedings to which the Royalty Trust is a party.

7. SUBSEQUENT EVENTS
The onshore Highlander subject interest began commercial production on February 25, 2015. Royalties paid to the Royalty Trust will not result in immediate distributions to the Royalty Trust unitholders because royalties are first subject to payment of loans outstanding, administrative expenses of the Royalty Trust and the establishment of a cash reserve for payment of future liabilities as determined at the discretion of the Trustee.

The Royalty Trust evaluated all other events subsequent to December 31, 2014, and through the date the Royalty Trust’s financial statements were issued, and determined that all events or transactions occurring during this period requiring recognition or disclosure were appropriately addressed in these financial statements.

8. SUPPLEMENTARY OIL AND GAS INFORMATION (UNAUDITED)
Proved Oil and Natural Gas Reserve Information. The following information summarizes the net proved reserves of oil and natural gas and the standardized measure as described below. All of the oil and natural gas reserves are located in the U.S.
The Royalty Trust believes the reserve estimates presented herein, in accordance with generally accepted engineering and evaluation principles consistently applied, are reasonable. However, there are numerous uncertainties inherent in estimating quantities and values of proved reserves and in projecting future rates of production, including many factors beyond the Royalty Trust's control. Reserve engineering is a subjective process of estimating the recovery from underground accumulations of oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Because all oil and natural gas reserve estimates are to some degree subjective, the quantities of oil and natural gas that are ultimately recovered, production and specified post-production costs and taxes allowable under the trust agreement and future crude oil and natural gas sales prices may all differ from those assumed in these estimates. In addition, different reserve engineers may make different estimates of reserve quantities and cash flows based upon the same available data. Therefore, the standardized measure of discounted future net cash flows (Standardized Measure) shown below represents estimates only and should not be construed as the current market value of the estimated reserves attributable to the overriding royalty interest associated with the subject interests. In this regard, the information set forth in the following tables includes revisions of reserve estimates attributable to proved properties any adjustments in the projected economic life of such properties resulting from changes in product prices.
Decreases in the prices of crude oil and natural gas could have an adverse effect on the carrying value of the proved reserves, reserve volumes and revenues, profitability and cash flows. The Royalty Trusts's reference prices for reserve determination are the WTI spot price for crude oil and the Henry Hub spot price for natural gas. As of March 12, 2015, the twelve-month average of the first-day-of-the-month historical reference price for natural gas has decreased from $4.35 per MMBtu at December 31, 2014, to $3.88 per MMBtu, while the comparable price for crude oil has decreased from $94.99 per barrel at December 31, 2014, to $82.72 per barrel.

	Natural Gas (MMcf)[a]	Oil (MBbls)[a]	Total (MMcfe)[a]
2014			
Proved reserves:			
Balance at beginning of year	687	7	729
Revisions of previous estimates	—	—	—
Extensions and discoveries	1,384	—	1,384
Acquisition of reserves in-place	—	—	—
Sale of reserves in-place	—	—	—
Purchase of reserves in-place	—	—	—
Production	—	—	—
Balance at end of year	2,071	7	2,113
Proved developed reserves at December 31, 2014	1,384	—	1,384
Proved undeveloped reserves at December 31, 2014	687	7	729

	Natural Gas (MMcf)	Oil (MBbls)	Total (MMcfe)
2013			
Proved reserves:			
Balance at beginning of year	—	—	—
Conveyance of overriding royalty interests (June 3, 2013)	856	9	910
Revisions of previous estimates	(169)	(2)	(181)
Extensions and discoveries	—	—	—
Acquisition of reserves in place	—	—	—
Sale of reserves in-place	—	—	—
Purchase of reserves in-place	—	—	—
Production	—	—	—
Balance at end of year	687	7	729
Proved developed reserves at December 31, 2013	—	—	—
Proved undeveloped reserves at December 31, 2013	687	7	729

(a) MMcf = millions of cubic feet; MBbls = thousands of barrels; MMcfe = MMcf equivalent

For the year ended December 31, 2014, reserves attributable to the Royalty Trust had a total of 1.4 Mmcfe of extensions and discoveries, all of which relate to the initial well drilled at the onshore Highlander subject interest. For the year ended December 31, 2013, proved undeveloped reserves were revised subsequent to McMoRan's contribution of the Lineham Creek subject interest to the Royalty Trust, which resulted from data obtained through additional drilling activities.

Standardized Measure. The Standardized Measure (discounted at 10 percent) from production of proved oil and natural gas reserves has been developed as of December 31, 2014, in accordance with SEC guidelines. McMoRan estimated the quantity of proved oil and natural gas reserves associated with the overriding royalty interest in the subject interests as well as the future periods in which they are expected to be produced based on year-end economic conditions. Estimates of future net revenues from the Royalty Trusts's proved oil and gas properties and the present value thereof were made using the twelve-month average of the first-day-of-the-month historical reference prices as adjusted for location and quality differentials, which are held constant throughout the life of the oil and gas properties, except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. Future gross revenues were reduced by estimated specified post-production costs and taxes in accordance with the trust agreement, all of which were based on current costs in

effect at December 31, 2014, and held constant throughout the life of the oil and gas properties. Future income taxes are not presented given the Royalty Trust's status a non-taxable "pass through" entity (See note 4).
The average realized sales prices used in the Royalty Trust's reserve report as of December 31, 2014, were $4.10 per one thousand cubic feet (Mcf) of natural gas and $94.99 per barrel of crude oil.
The Standardized Measure related to proved oil and natural gas reserves as of December 31, 2014 and 2013 follows:

	December 31, 2014	December 31, 2013
Future cash inflows	$ 9,143,214	$ 3,207,065
Future costs applicable to future cash flows:		
Production costs (primarily production and ad valorem taxes)	(458,447)	(139,684)
Development and abandonment costs	—	—
Future income taxes [(a)]	—	—
Future net cash flows	8,684,767	3,067,381
Discount for estimated timing of net cash flows (10% discount rate) [(b)]	(1,824,710)	(658,353)
Standardized measure	$ 6,860,057	$ 2,409,028

(a) No taxes are presented given the Royalty Trust's status as a non-taxable "pass-through" entity (see Note 4).

(b) Amounts reflect application of the required 10% discount rate to the estimated future net cash flows associated with production of estimated proved reserves.

A summary of the principal sources of changes in the Standardized Measure for the years ended December 31 2014 and 2013 follows:

	2014	2013
Balance at beginning of year	$ 2,409,028	$ —
Changes during the year		
Conveyance of overriding royalty interests (June 3, 2013)	—	2,713,309
Sales, net of production expense	—	—
Net changes in sales and transfer prices, net of production expenses	253,036	282,189
Extensions, discoveries and improved recoveries	4,266,500	—
Changes in estimated future development costs	—	—
Previously estimated development costs incurred during the year	—	—
Sales of reserves in-place	—	—
Revisions of quantity estimates	—	(761,070)
Changes due to timing and other	(309,410)	—
Accretion of discount	240,903	174,600
Net change in income taxes	—	—
Total changes	4,451,029	2,409,028
Balance at end of year	$ 6,860,057	$ 2,409,028

9. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	Royalty Income	Administrative Expenses in Excess of Income	Distributable Income	Distributable Income Per Unit (a)
2014				
1st Quarter	$ —	$ (69,085)	$ —	$ —
2nd Quarter	—	(301,836)	—	—
3rd Quarter	—	(99,312)	—	—
4th Quarter	—	(133,146)	—	—
	$ —	$ (603,379)	$ —	$ —
2013				
1st Quarter	$ —	$ —	$ —	$ —
2nd Quarter	—	(221,938)	—	—
3rd Quarter	—	(242,359)	—	—
4th Quarter	—	(141,862)	—	—
	$ —	$ (606,159)	$ —	$ —

(a) As of December 31, 2014, none of the subject interests have had any associated commercial production. As such, there has been no distributable income for disbursement to the Royalty Trust unitholders. However, the onshore Highlander subject interest began commercial production on February 25, 2015. Royalties paid to the Royalty Trust will not result in immediate distributions to the Royalty Trust unitholders because royalties are first subject to payment of loans outstanding, administrative expenses of the Royalty Trust and the establishment of a cash reserve for payment of future liabilities as determined at the discretion of the Trustee.

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

Not Applicable.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

Evaluation of disclosure controls and procedures. The Royalty Trust has no employees, and, therefore, does not have a principal executive officer or principal financial officer. Accordingly, the Trustee is responsible for making the evaluations, assessments and conclusions required pursuant to this Item 9A. The Trustee has evaluated the effectiveness of the Royalty Trust’s “disclosure controls and procedures” (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the Exchange Act)) as of the end of the period covered by this Form 10-K. Based on this evaluation, the Trustee has concluded that the Royalty Trust’s disclosure controls and procedures are effective as of the end of the period covered by this Form 10-K.

Due to the nature of the Royalty Trust as a passive entity and in light of the contractual arrangements pursuant to which the Royalty Trust was created, including the provisions of (i) the amended and restated royalty trust agreement and (ii) the master conveyance, the Royalty Trust's disclosure controls and procedures necessarily rely on (A) information provided by FCX, including information relating to results of operations, the costs and revenues attributable to the subject interests and other operating and historical data, plans for future operating and capital expenditures, reserve information, information relating to projected production, and other information relating to the status and results of operations of the subject interests and the overriding royalty interests, and (B) conclusions and reports regarding reserves by the Royalty Trust's independent reserve engineers.

Internal Control Over Financial Reporting

(a) Trustee’s Annual Report on Internal Control over Financial Reporting. The Bank of New York Mellon Trust Company, N.A., as Trustee of the Royalty Trust, is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) and 15d-15(f) promulgated under the Exchange Act. The Trustee conducted an evaluation of the effectiveness of the Royalty Trust’s internal control over financial reporting based on the criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 Framework) (the “COSO criteria”). Based on the Trustee’s evaluation under the COSO criteria, the Trustee concluded that the Royalty Trust’s internal control over financial reporting was effective as of December 31, 2014.

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.

(b) Attestation Report of the Registered Public Accounting Firm. Ernst & Young LLP, an independent registered public accounting firm who audited the Royalty Trust’s financial statements included in this Form 10-K, has issued an attestation report on the Royalty Trust's internal control over financial reporting, which is included in Part II, Item 8. “Financial Statements and Supplementary Data” of this Form 10-K.

(c) Changes in Internal Control over Financial Reporting. During the quarter ended December 31, 2014, there has been no change in the Royalty Trust's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the Royalty Trust's internal control over financial reporting. The Trustee notes for purposes of clarification that it has no authority over, and makes no statement concerning, the internal control over financial reporting of FCX.

Item 9B. Other Information

Not Applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The Royalty Trust has no directors, officers or employees, and, therefore, the Royalty Trust has not adopted a Code of Ethics and the Royalty Trust does not have an audit committee or nominating committee. The Royalty Trust is administered by the Trustee pursuant to the royalty trust agreement. The royalty trust agreement grants the Trustee only the rights and powers necessary to achieve the purposes of the Royalty Trust. For more information on the rights and duties of the Trustee, see Part I, Items 1. and 2. "Business and Properties - The Royalty Trust - The Royalty Trust Agreement - Duties and Limited Powers of the Trustee" of this Form 10-K.

Section 16(a) Beneficial Ownership Reporting Compliance
The Royalty Trust has no directors or officers. Accordingly, only beneficial owners of more than 10% of the royalty trust units are required to file with the SEC initial reports of beneficial ownership of royalty trust units and reports of changes in such ownership pursuant to Section 16(a) of the Exchange Act. Based solely upon a review of these reports and any amendments thereto furnished to the Trustee, the Trustee is not aware of any person having failed to file on a timely basis the reports required by Section 16(a) of the Exchange Act during the most recent fiscal year or prior fiscal

years.

Item 11. Executive Compensation

The Royalty Trust has no directors, officers or employees. For information regarding the compensation paid to the Trustee, see Part I, Items 1. and 2. "Business and Properties - The Royalty Trust - The Royalty Trust Agreement - Compensation of the Trustee" of this Form 10-K. The Royalty Trust does not have a board of directors, and it does not have a compensation committee.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Royalty Trust Unitholder Matters

Security Ownership of Certain Beneficial Owners

Based on filings with the SEC, the table below shows the beneficial owners of more than 5% of the outstanding royalty trust units. Unless otherwise indicated, all information is presented as of December 31, 2014 and all royalty trust units beneficially owned are held with sole voting and investment power.

Name and Address of Beneficial Owner	Total Number of Royalty Trust Units Beneficially Owned	Percent of Outstanding Royalty Trust Units[a]
Freeport-McMoRan Inc. McMoRan Oil & Gas LLC 333 North Central Avenue Phoenix, AZ 85004	62,285,438 [b]	27.1%
Mount Kellett Capital Management LP 623 Fifth Avenue, 18th Floor New York, NY 10022	36,669,004 [c]	15.9%
Leon G. Cooperman 11431 W. Palmetto Park Road Boca Raton, FL 33428	23,783,993 [d]	10.3%
Paulson & Co. Inc. 1251 Avenue of the Americas New York, NY 10020	11,894,856 [e]	5.2%

(a) Based on 230,172,696 royalty trust units outstanding as of December 31, 2014.

(b) Based on a Schedule 13G filed with the SEC on February 11, 2015 by FCX and McMoRan.

(c) Based on a Form 4 filed with the SEC on January 24, 2014 by Mount Kellett Capital Management LP LLC on behalf of certain affiliated funds and managed accounts.

(d) Based on a Form 4 filed with the SEC on February 20, 2015 by Leon G. Cooperman, on his own behalf and on behalf of affiliated investment firms and managed accounts identified therein. Mr. Cooperman, has (a) sole voting and investment power over 17,453,773 of the royalty trust units reported and (b) shared voting and investment power over 6,330,220 of the royalty trust units reported.

(e) Based on an amended Schedule 13G filed with the SEC on February 17, 2015 by Paulson & Co. Inc. on behalf of affiliated funds and managed accounts.

The Royalty Trust has no directors, executive officers or employees, and therefore, has no equity compensation plans and no ownership of management to report. The Trustee knows of no arrangement, including the pledge of royalty trust units, the operation of which may at a subsequent date result in a change in control of the Royalty Trust.

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

Other than (a) its formation, (b) its receipt of contributions and loans from FCX for administrative and other expenses as provided for in the royalty trust agreement, (c) its payment of such administrative and other expenses and (d) its receipt of the conveyance of the overriding royalty interests from McMoRan pursuant to the master conveyance, the Royalty Trust has not conducted any activities or entered into any transactions.

Funding of Administrative Expenses. Pursuant to the royalty trust agreement, FCX has agreed to pay annual trust expenses up to a maximum amount of $350,000, with no right of repayment or interest due, to the extent the Royalty Trust lacks sufficient funds to pay administrative expenses. During each of the years ended December 31, 2014 and 2013, FCX contributed $350,000 to the Royalty Trust with respect to this arrangement. In addition to such annual contributions, FCX has agreed to lend money, on an unsecured, interest-free basis, to the Royalty Trust to fund the Royalty Trust's ordinary administrative expenses as set forth in the royalty trust agreement. During the years ended December 31, 2014 and 2013, FCX loaned $200,000 and $450,000, respectively, to the Royalty Trust under this arrangement, none of which has been repaid as of December 31, 2014.

Pursuant to the royalty trust agreement, FCX agreed to provide and maintain a $1.0 million stand-by reserve account or an equivalent letter of credit for the benefit of the Royalty Trust to enable the Trustee to draw on such reserve account or letter of credit to pay obligations of the Royalty Trust in the event that it has inadequate funds to pay its obligations at any time. Currently, with the consent of the Trustee, FCX may reduce the reserve account or substitute a letter of credit with a different face amount for the original letter of credit or any substitute letter of credit. In connection with this arrangement, FCX has provided $1.0 million in the form of a reserve fund cash account to the Royalty Trust, which amount is reflected as reserve fund cash with a corresponding reserve fund liability in the accompanying Statements of Assets, Liabilities and Trust Corpus. The Royalty Trust has not drawn any funds from the reserve account, and FCX has not requested a reduction of such reserve account. For additional information regarding the royalty trust agreement, see Note 2.

Compensation of the Trustee. The Trustee is paid the sum of $150,000 per year until the first year in which the Royalty Trust receives any payment pursuant to the conveyances of the overriding royalty interests, at which time such sum will be increased to $200,000 per year. The onshore Highlander subject interest began commercial production on February 25, 2015. Accordingly, it is anticipated that the Trustee will be paid $200,000 per year beginning in 2015. Additionally, the Trustee receives reimbursement for its reasonable out-of-pocket expenses incurred in connection with the administration of the Royalty Trust. The Trustee’s compensation is paid out of the Royalty Trust’s assets. The Trustee has a lien on the Royalty Trust’s assets to secure payment of its compensation and any indemnification expenses and other amounts to which it is entitled under the royalty trust agreement.

Royalty Trust Units Held by FCX. At December 31, 2014, the Royalty Trust had 230,172,696 royalty trust units outstanding and FCX, through its indirect wholly owned subsidiary McMoRan, held 62,285,438 royalty trust units (or 27.1% of the outstanding royalty trust units). FCX is currently the largest holder of outstanding royalty trust units. The Royalty Trust has no directors.

Item 14. Principal Accounting Fees and Services

Fees and Related Disclosures for Accounting Services

The following table discloses the fees for professional services billed to the Royalty Trust by Ernst & Young LLP in each of the last two fiscal years:

	2014	2013
Audit Fees	$ 200,000	$ 150,000
Audit-Related Fees	—	—
Tax Fees	—	—
All Other Fees	—	—

The Royalty Trust has no audit committee, and as a result, has no audit committee pre-approval policies and procedures with respect to fees paid to Ernst & Young LLP. Any pre-approval or approval of any services performed by the principal auditor or any other professional service firms and related fees are granted by the Trustee.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a)(1) Financial Statements. Reference is made to Part II, Item 8. "Financial Statements and Supplementary Data" of this Form 10-K.

(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 on page E-1 hereof.

GLOSSARY

In this report the following terms have the meanings specified below.

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

Block. A block depicted on the Outer Continental Shelf Leasing and Official Protraction Diagrams issued by the BOEM (defined below) or a similar depiction on official protraction or similar diagrams issued by a state bordering on the Gulf of Mexico.

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 on October 1, 2011, and responsible for pre-leasing environmental and leasing matters).

BSEE. The Bureau of 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 on 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 well, the reporting to the appropriate authority that the well has been abandoned.

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. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

Gross well or gross acre. A well or acre in which the registrant owns a working interest. The number of gross wells is the total number of wells in which the registrant owns a working interest.

MMcfe. Million cubic feet equivalent, determined using the ratio of six thousand cubic feet (Mcf) of natural gas to one barrel of crude oil, condensate or natural gas liquids.

Net well or net acre. Deemed to exist when the sum of the fractional ownership working interests in gross wells or gross acres equals one. The number of net wells or net acres is the sum of the fractional working interests owned in

gross wells or gross acres expressed as whole numbers and fractions of whole numbers.
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.

Possible reserves. Those additional reserves that are less certain to be recovered than probable reserves.

Probable reserves. Those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

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.

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.

Working interest. An interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations.

For additional information regarding the definitions contained in this Glossary, and for other oil and gas definitions, please see Rule 4-10 of Regulation S-X.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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.

Gulf Coast Ultra Deep Royalty Trust
By: The Bank of New York Mellon
Trust Company, N.A., as Trustee

By: /s/ Michael J. Ulrich
Michael J. Ulrich
Vice President

Date: March 16, 2015

The Registrant, Gulf Coast Ultra Deep Royalty Trust, has no principal executive officer, principal financial officer, controller or principal accounting officer, board of directors or persons performing similar functions. Accordingly, no additional signatures are available and none have been provided. In signing the report above, the Trustee does not imply that it has performed any such function or that any such function exists pursuant to the terms of the amended and restated royalty trust agreement, dated June 3, 2013, under which it serves.

Appendix A-1

GULF COAST ULTRA DEEP ROYALTY TRUST

PROVED RESERVES

Estimated

Future Reserves and Income

Attributable to Certain

Royalty Interests

SEC Parameters

As of

December 31, 2014

\s\ Val Rick Robinson
Val Rick Robinson, P.E.
TBPE License No. 105137
Senior Vice President
[SEAL]
RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA STREET SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

March 13, 2015

Gulf Coast Ultra Deep Royalty Trust
The Bank of New York Mellon Trust Company, N.A., as trustee
Attn: Michael J. Ulrich
Institutional Trust Services
919 Congress Avenue, Suite 500
Austin, Texas 78701

Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain royalty interests of Gulf Coast Ultra Deep Royalty Trust (the Trust) as of December 31, 2014. The subject properties are located in the state of Louisiana. The reserves found herein are derived from the reserves evaluation prepared for Freeport-McMoRan Oil & Gas LLC (FM O&G), a wholly owned subsidiary of Freeport-McMoRan Inc. (FCX), as of December 31, 2014. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on January 8, 2015, and presented herein, was prepared for public disclosure by The Bank of New York Mellon Trust Company, N.A. (the Trustee), on behalf of Gulf Coast Ultra Deep Royalty Trust in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott account for a portion of FM O&G's total net proved reserves as of December 31, 2014. Based on information provided by FM O&G, the third party estimate conducted by Ryder Scott addresses 100 percent of the total proved net liquid hydrocarbon reserves, and 33 percent of the total proved net gas reserves of the Trust.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2014 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized below.

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March 13, 2015
Page 2

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Royalty Interests of
Gulf Coast Ultra Deep Royalty Trust
As of December 31, 2014

	Total Proved Undeveloped
Net Remaining Reserves	
Oil/Condensate - Barrels	6,868
Gas - MMCF	687
Income Data	
Future Gross Revenue	$3,467,209
Deductions	77,642
Future Net Income (FNI)	$3,389,567
Discounted FNI @ 10%	$2,593,557

Liquid hydrocarbons are expressed in standard 42 gallon barrels. All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located.

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package PHDWin Petroleum Economic Evaluation Software, a copyrighted program of TRC Consultants L.C. The program was used at the request of FM O&G. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, recompletion costs, and development costs. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income. Because the interests evaluated herein include only royalty interests, no operating or development costs are shown; however, these costs have been considered in determining economic limits of these properties.

Gas reserves account for approximately 82 percent and liquid hydrocarbon reserves account for the remaining 18 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

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March 13, 2015
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Discount Rate Percent	Discounted Future Net Income As of December 31, 2014 Total Proved
8	$2,734,030
15	$2,276,953
20	$2,003,669
25	$1,767,181

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "Petroleum Reserves Definitions" is included as an attachment to this report.

The various reserve status categories are defined under the attachment entitled "Petroleum Reserves Status Definitions and Guidelines" in this report.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At the Trustee's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

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." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserve estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

FM O&G's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which the Trust owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely than not to be achieved." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserve category must meet the SEC definitions as noted above.

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March 13, 2015
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Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

All of the proved undeveloped reserves included herein were estimated by the volumetric method. The volumetric analysis utilized pertinent well and seismic data furnished to Ryder Scott by FM O&G or which we have obtained from public data sources that were available through December 2014. The data utilized from the well and seismic data incorporated into our volumetric analysis were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

FM O&G has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by FM O&G with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by FM O&G. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by FM O&G. Wells or locations

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

Gulf Coast Ultra Deep Royalty Trust
March13, 2015
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that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

FM O&G furnished us with the above mentioned average prices in effect on December 31, 2014. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used for the geographic area included in the report. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices that were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by FM O&G. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by FM O&G to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves by reserve category for the geographic area and presented in accordance with SEC disclosure requirements for each of the geographic areas included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Proved Realized Prices
United States	Oil/Condensate	WTI Cushing	$94.99/Bbl	$94.99/Bbl
	Gas	Henry Hub	$4.35/MMBTU	$4.38/MCF

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report are based on the operating expense reports of FM O&G and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. Other costs such as transportation and/or processing fees are included as deductions. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by FM O&G. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by FM O&G and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs.

The proved undeveloped reserves in this report have been incorporated herein in accordance with FM O&G's plans to develop these reserves as of December 31, 2014. The implementation of FM O&G's development plans as presented to us and incorporated herein is subject to the approval process adopted by FM O&G's management. As the result of our inquiries during the course of preparing this report, FM O&G has informed us that the development activities included herein have been subjected to and received the internal approvals required by FM O&G's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to FM O&G. FM O&G has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, FM O&G has informed us that they are not aware of any legal, regulatory or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2014, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by FM O&G were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer’s license or a registered or certified professional geoscientist’s license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to both FM O&G and the Trust. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC on behalf of the Trust.

We have provided the Trustee with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made on behalf of the Trust and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

\s\ Val Rick Robinson

Val Rick Robinson, P.E.
TBPE License No. 105137
Senior Vice President
[SEAL]
VRR (DPR)/pl

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

Professional Qualifications of Primary Technical Engineer

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Val Rick Robinson was the primary technical person responsible for the estimate of the reserves, future production and income presented herein.

Mr. Robinson, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Robinson served in a number of engineering positions with ExxonMobil Corporation. For more information regarding Mr. Robinson's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Company/Employees.

Mr. Robinson earned a Bachelor of Science degree in Chemical Engineering from Brigham Young University in 2003 and is a licensed Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Robinson fulfills. As part of his 2014 continuing education hours, Mr. Robinson attended 20 hours of formalized training including the 2014 RSC Reserves Conference and various professional society presentations covering such topics as the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register, the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering, overviews of the various productive basins of North America, computer software, and professional ethics.

Based on his educational background, professional training and more than 11 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Robinson has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

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PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale.

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PETROLEUM RESERVES DEFINITIONS
Page 2

Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

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. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

PETROLEUM RESERVES DEFINITIONS
Page 3

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES
Page 2

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) completion intervals which are open at the time of the estimate, but which have not started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

Appendix A-2

March 16, 2015

The Bank of New York Mellon Trust Company, N.A., as Trustee
Gulf Coast Ultra Deep Royalty Trust
919 Congress, Suite 500
Austin, Texas 78701

Ladies and Gentlemen:

In accordance with your request, we have estimated the proved developed non-producing reserves and future revenue, as of December 31, 2014, to the Gulf Coast Ultra Deep Royalty Trust (Gulf Coast) overriding royalty interest in certain gas properties located in Bayou Long Field, St. Martin Parish, Louisiana. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in the report constituted approximately 66 percent of all proved reserves owned by Gulf Coast. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities-Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Gulf Coast's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the gas reserves and future net revenue to the Gulf Coast interest in Bayou Long Field, as of December 31, 2014, to be:

	Gas Reserves (MMCF)		Future Net Revenue (M$)	
Category	Gross (100%)	Net	Total	Present Worth at 10%
Proved Developed Non-Producing	38,447.4	1,384.1	5,295.2	4,266.5

Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases. These properties are not expected to produce commercial volumes of condensate.

The estimates in this report are for proved developed non-producing reserves. Our study indicates that there are no proved developed producing or proved undeveloped reserves for these properties at this time. As requested, probable and possible reserves that exist for these properties have not been included. This report does not include any value that could be attributed to interests in undeveloped acreage. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Gross revenue is Gulf Coast's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Gulf Coast's share of production taxes and ad valorem taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

The gas price used in this report is based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2014. The average Henry Hub spot price of

$4.350 per MMBTU is adjusted for energy content, transportation fees, and market differentials. The adjusted gas price of $3.961 per MCF is held constant throughout the lives of the properties.

Because Gulf Coast owns no working interest in these properties, no operating costs or capital costs would be incurred. However, estimated operating costs and capital costs have been used to confirm economic producibility and determine economic limits for the properties. These cost estimates were provided by Freeport-McMoran LLC (FM O&G), the operator of the properties. Operating costs include only direct lease- and field-level costs and have been divided into per-well costs and per-unit of production costs. Since all properties are nonoperated, headquarters general and administrative overhead expenses of Gulf Coast are not included. Capital costs are based on internal planning budgets of FM O&G. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Operating costs and capital costs are not escalated for inflation. Gulf Coast would not incur any costs due to abandonment, nor would it realize any salvage value for the lease and well equipment.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

The reserves in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by FM O&G, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred by the working interest owners in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Gulf Coast, FM O&G, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. John R. Cliver, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2009 and has over 5 years of prior industry experience. Shane M. Howell, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2005 and has over 7 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By:	/s/ John R. Cliver	By:	/s/ Shane M. Howell
	John R. Cliver, P.E. 107216		Shane M. Howell, P.G. 11276
	Vice President		Vice President
Date Signed:	March 16, 2015	Date Signed:	March 16, 2015

JRC:JLM

Please be advised that the digital document you are viewing is provided by Netherland, Sewell & Associates, Inc. (NSAI) as a convenience to our clients. The digital document is intended to be substantively the same as the original signed document maintained by NSAI. The digital document is subject to the parameters, limitations, and conditions stated in the original document. In the event of any differences between the digital document and the original document, the original document shall control and supersede the digital document.

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4 10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities-Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) Acquisition of properties. Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) Analogous reservoir. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) Bitumen. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) Condensate. Condensate is 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.

(5) Deterministic estimate. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) Developed oil and gas reserves. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:
Developed Producing Reserves - Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered

producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves - Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

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Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(7) Development costs. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) Development project. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) Development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) Economically producible. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) Estimated ultimate recovery (EUR). Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) Exploration costs. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) Exploratory well. An exploratory well is 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. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) Extension well. An extension well is a well drilled to extend the limits of a known reservoir.

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Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(15) 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. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) Oil and gas producing activities.

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term saleable hydrocarbons means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) Possible reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

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Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) Probable reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) Probabilistic estimate. The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) Production costs.

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

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(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) Proved area. The part of a property to which proved reserves have been specifically attributed.

(22) 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. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) Proved properties. Properties with proved reserves.

(24) Reasonable certainty. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90%

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probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) Reliable technology. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) Reserves. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities-Oil and Gas:
932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)
b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.
932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.
b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.
c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.

d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.
e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.
f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.

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

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Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(28) Resources. Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) Service well. A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) Stratigraphic test well. A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) Undeveloped oil and gas reserves. Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):
Although several types of projects - such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations - by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.
Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);
The company's historical record at completing development of comparable long-term projects;
The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;
The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and
The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) Unproved properties. Properties with no proved reserves.

Gulf Coast Ultra Deep Royalty Trust
Exhibit Index

Exhibit Number	Exhibit Title	Filed with this Form 10-K	Incorporated by Reference Form	File No.	Date Filed
3.1	Composite Certificate of Trust of Gulf Coast Ultra Deep Royalty Trust		10-Q	333-185742	August 14, 2013
10.1	Amended and Restated Royalty Trust Agreement of Gulf Coast Ultra Deep Royalty Trust, dated as of June 3, 2013		8-K	333-185742	June 4, 2013
10.2	Master Conveyance of Overriding Royalty Interest by and between McMoRan Oil & Gas LLC and Gulf Coast Ultra Deep Royalty Trust, dated as of June 3, 2013		8-K	333-185742	June 4, 2013
23.1	Consent of Ryder Scott Company, L.P.	X			
23.2	Consent of Netherland, Sewell & Associates, Inc.	X			
31	Certification pursuant to Rule 13a-14(a)/15d-14(a)	X			
32	Certification pursuant to 18 U.S.C. Section 1350	X			
99.1	Report of Ryder Scott Company, L.P.	X			
99.2	Report of Netherland, Sewell & Associates, Inc.	X			