Gulf Coast Ultra Deep Royalty Trust
Form 10-K
March 21, 2019

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, 2018
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 601 Travis Street, 16th Floor Houston, TX	77002
(Address of principal executive offices)	(Zip Code)

(512) 236-6599

(Registrant's telephone number, including area code)

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

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

Royalty Trust Units

(Title of Class)
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 every Interactive Data File required to be submitted 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 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. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer o	Accelerated filer o
Non-accelerated filer x	Smaller reporting company x
	Emerging growth company o

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. o
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 $10.5 million on June 29, 2018.

On February 28, 2019, there were outstanding 230,172,696 royalty trust units representing beneficial interests in the registrant.

DOCUMENTS INCORPORATED BY REFERENCE
NONE

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FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (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 (Exchange Act). 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) or the trading market for the royalty trust units, all statements regarding the respective plans of McMoRan Oil & Gas LLC (McMoRan) or Highlander Oil & Gas Assets LLC (HOGA) for the subject interests (as defined in this Form 10-K); the potential results of any drilling on the subject interests by the applicable operator; anticipated interests of McMoRan or HOGA and the Royalty Trust in any of the subject interests; McMoRan’s or HOGA's geologic models and the nature of the geologic trend in the Gulf of Mexico and onshore in South Louisiana discussed in this Form 10-K; all statements regarding any belief or understanding of the nature or potential of the subject interests; and estimates regarding the anticipated effects of the Tax Cuts and Jobs Act (“TCJA”) enacted on December 22, 2017. The words “anticipates,” “may,” “can,” “plans,” “believes,” “estimates,” “expects,” “projects,” “intends,” “likely,” “will,” “should,” "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 Freeport-McMoRan Inc.'s (FCX) future plans for its remaining oil and gas properties; the risk that the subject interests will not produce additional 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, McMoRan or HOGA not to develop and/or transfer the subject interests; any inability of FCX, McMoRan or HOGA to develop the subject interests; damages to facilities resulting from natural disasters or accidents; fluctuations in the market price, volume and frequency of the trading market for the royalty trust units; the amount of cash received or expected to be received by the Trustee from the underlying subject interests on or prior to a record date for a cash distribution; additional implementation guidance, changes in assumptions, and potential future refinements of or revisions to calculations; and other factors described in Part I, Item 1A. “Risk Factors” of this Form 10-K. Any differences in actual cash receipts by the Royalty Trust could affect the amount of cash distributions.

Investors are cautioned that test results and current production rates may not be indicative of future production rates or of the amounts of hydrocarbons that a well may produce, and 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 United States (U.S.) Securities and Exchange Commission (SEC) pursuant to Section 13(a) or 15(d) of the Exchange Act 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 are available, free of charge, through our website, http://gultu.investorhq.businesswire.com. 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 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 52.

THE ROYALTY TRUST

The Royalty Trust. 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 oil and gas assets are held through its wholly owned subsidiary, FCX Oil & Gas LLC (FM O&G). As a result of the merger, MMR and McMoRan are both indirect wholly owned subsidiaries of FM O&G.

The Royalty Trust is a statutory trust created as contemplated by the merger agreement 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 Inboard Lower Tertiary/Cretaceous exploration prospects located in the shallow waters 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 acquired by FCX pursuant to the merger and were not considered part of FCX's purchase consideration of MMR.

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 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, 2018, only the onshore Highlander subject interest had any reserves classified as proved, probable or possible and had established commercial production. On February 5, 2019, McMoRan completed the sale of all of its rights, title and interest in and to the onshore Highlander subject interest pursuant to a purchase and sale agreement with HOGA (the Highlander Sale). The onshore Highlander subject interest was sold subject to the overriding royalty interest in future production held by the Royalty Trust. As a result of the Highlander Sale, HOGA has a 72 percent working interest and an approximate 49 percent net revenue interest in the onshore Highlander subject interest. The Royalty Trust continues to hold a 3.6 percent overriding royalty interest in the onshore Highlander subject interest. McMoRan will remain operator of the onshore Highlander subject interest during a transition period until HOGA qualifies and is designated as operator, which is expected to occur on or before May 31, 2019. McMoRan has informed the Trustee that it has no plans to pursue, has relinquished, has allowed to expire or has sold all of the subject interests.

At December 31, 2018, FCX through its wholly owned subsidiary McMoRan, held 62,286,299 royalty trust units (or 27.1% of the outstanding royalty trust units). In connection with the Highlander Sale on February 5, 2019, McMoRan assigned 31,143,150 royalty trust units to HOGA. 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 subsidiaries.

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, on behalf of the Royalty Trust, 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, (d) its repayment of loans from FCX, (e) its receipt of the conveyance of the overriding royalty interests from McMoRan pursuant to the master conveyance, (f) its receipt of royalties from McMoRan, and (g) its cash distributions to unitholders, if any, 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.

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 $350,000, with no right of repayment or interest due, to the extent the Royalty Trust lacks sufficient funds to pay administrative expenses. No such contributions were made during the years ended December 31, 2018 and 2017. 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. Since inception, FCX has loaned $650,000 to the Royalty Trust under this arrangement, all of which had been repaid prior to December 31, 2018, including $500,000 during 2017, and no amounts were outstanding at December 31, 2018. All funds the Trustee borrows to cover expenses or liabilities, whether from FCX or from any other source, must be repaid before the Royalty Trust unitholders will receive any distributions.

Pursuant to the royalty trust agreement, FCX 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 if its funds are inadequate 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. As of December 31, 2018, the Royalty Trust had not drawn any funds from the reserve account, and FCX had 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 will 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 the affirmative 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 66 % of the outstanding royalty trust units to (i) approve a sale of all or substantially all of the overriding royalty interests or (ii) terminate the Royalty Trust requires the affirmative vote of holders of 66 % or more of the outstanding royalty trust units held by persons other than FCX or its affiliates.

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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, as long as 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’s annual compensation has been $200,000 since 2016, when it increased from $150,000 as a result of the Royalty Trust’s receipt of royalties related to production from the onshore Highlander subject interest beginning in the second quarter of 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 the affirmative 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). The affirmative vote of the holders of 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 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 the affirmative vote of 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 earliest to occur 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 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. In addition, 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 following the end of such nine-month period. The volume-weighted average price per royalty trust unit was $0.05 for the nine-month period ended March 15, 2019.

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 FCX's receipt of such notice, the annual fee payable to the Trustee will be increased by 5% as of the end of such 90-day period, 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 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 generally has none of the rights described in the preceding sentence, and neither the Royalty Trust nor the Royalty Trust unitholders has any such rights.

The Royalty Trust's 5% gross overriding royalty interest in future production from each subject interest is proportionately reduced based on McMoRan's or HOGA's respective working interest in the subject interest. 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 none of McMoRan, FCX or HOGA 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 similar 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. Royalties received by the Royalty Trust must first be used to (i) satisfy Royalty Trust administrative expenses and (ii) reduce Royalty Trust indebtedness. The Royalty Trust had no indebtedness outstanding as of December 31, 2018. Additionally, the Trustee has established a minimum cash reserve of $250,000. As a result, distributions will be made to Royalty Trust unitholders only when royalties received less administrative expenses incurred and repayment of any indebtedness exceeds the $250,000 minimum cash reserve. Distributable income totaled $838,155 and $356,486 for the years ended December 31, 2018 and 2017. On January 17, 2019, the Royalty Trust declared a cash distribution of $0.001108 per unit payable on February 13, 2019, to unitholders of record on January 30, 2019. These distributions are not necessarily indicative of future distributions. The Royalty Trust's only other sources of liquidity are mandatory annual contributions, any loans and the required standby reserve account or letter of credit from FCX. As a result, any material adverse change in FCX's or McMoRan's financial condition or results of operations could materially and adversely affect the Royalty Trust and the underlying royalty trust units. 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.

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 govern all matters affecting the title, ownership or transfer of royalty trust units.

Periodic Reports. Within 45 days following the end of each of the first three fiscal quarters, and within 90 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. In connection with the completion of the Highlander Sale, HOGA assumed all administrative and reporting responsibilities with respect to the Royalty Trust, including those described in Article III of the royalty trust agreement. During a transition period that is expected to end on or before May 31, 2019, McMoRan will make, on HOGA's behalf, but with HOGA's assistance, all filings required to be made in connection with the Royalty Trust. Pursuant to the royalty trust agreement, the Royalty Trust and the Trustee are entitled to rely on the information provided without investigation and are fully protected and will incur no liability in doing so. 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. Nevertheless, courts in jurisdictions outside of Delaware may not 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 originally consisted of 20 specified Inboard Lower Tertiary/Cretaceous prospects (with target depths generally greater than 18,000 feet total vertical depth) located in the shallow waters of the Gulf of Mexico and onshore in South Louisiana. The offshore subject interests consisted 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 consisted of (1) Highlander; (2) Lineham Creek; and (3) Tortuga.

As of December 31, 2018, only the onshore Highlander subject interest had any reserves classified as proved, probable or possible and had established commercial production. On February 5, 2019, McMoRan completed the the Highlander Sale. The onshore Highlander subject interest was sold subject to the overriding royalty interest in future production held by the Royalty Trust. As a result of the Highlander Sale, HOGA has a 72 percent working interest and an approximate 49 percent net revenue interest in the onshore Highlander subject interest. The Royalty Trust continues to hold a 3.6 percent overriding royalty interest in the onshore Highlander subject interest. McMoRan will remain operator of the onshore Highlander subject interest during a transition period until HOGA qualifies and is designated as operator, which is expected to occur on or before May 31, 2019. McMoRan has informed the Trustee that it has no plans to pursue, has relinquished, has allowed to expire or has sold all of the subject interests.

Exploratory and Development Drilling. McMoRan did not drill any exploration or development wells on the subject interests during the years ended December 31, 2018 and 2017. Additionally, there were no in-progress or suspended wells associated with the subject interests during the years ended December 31, 2018 and 2017.

The onshore Highlander subject interest is the only producing subject interest and 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. During the year ended December 31, 2018, the Royalty Trust received royalties of

$1,462,796 from McMoRan related to 576,120 thousand cubic feet (Mcf) of gas production attributable to the onshore Highlander subject interest with average post-production costs of $0.31 per Mcf and an average receipt price of $2.85 per Mcf. During the year ended December 31, 2017, the Royalty Trust received royalties of $1,376,758 from McMoRan related to 525,972 Mcf of gas production attributable to the onshore Highlander subject interest with average post-production costs of $0.30 per Mcf and an average receipt price of $2.91 per Mcf.

Acreage. At December 31, 2018, McMoRan owned interests in approximately 142 oil and gas leases in the shallow waters of the Gulf of Mexico and onshore in South Louisiana, covering approximately 14,009 gross acres (7,069 acres net to McMoRan's interests) associated with the subject interests, less than one percent of which are scheduled to expire between 2019 and 2021. Whether or not McMoRan or HOGA maintains the acreage scheduled to expire will be determined by McMoRan's and HOGA's respective current and future plans, over which the Royalty Trust has no control. McMoRan has informed the Trustee that it has no plans to pursue, has relinquished, has allowed to expire, or has sold all of the subject interests.

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, 2018.

	Developed (a)		Undeveloped (b)	
	Gross Acres	Net Acres	Gross Acres	Net Acres
Offshore (federal waters)	—	—	5,000	600
Onshore South Louisiana	9,000	6,463	9	6
Total as of December 31, 2018	9,000	6,463	5,009	606

(a) In connection with the Highlander Sale on February 5, 2019, all of the developed acreage was sold to HOGA.

(b) As a result of impairment charges recorded in 2015 and prior years, there is no carrying value associated with undeveloped acreage remaining at December 31, 2018, as McMoRan has informed the Trustee that it has no plans to pursue any of the subject interests associated with this acreage.

Natural Gas Reserves. McMoRan's estimated proved reserves related to the subject interests are based upon a reserve report prepared by Netherland, Sewell & Associates, Inc. (NSAI), an independent petroleum engineering firm. A copy of NSAI's reserve report is filed as an exhibit to this Form 10-K. These reserve estimates are prepared in accordance with guidelines established by the SEC as prescribed by Regulation S-X, Rule 4-10. McMoRan's technical staff estimates, with reasonable certainty, the economically producible natural gas associated with the subject interests. The practices for estimating hydrocarbons in place include, but are not limited to, mapping, seismic interpretation of two-dimensional and/or three-dimensional data, core analysis, mechanical properties of formations, thermal maturity, well logs of existing penetrations, correlation of known penetrations, decline curve analysis of producing locations with significant production history, well testing, static bottom hole testing, flowing bottom hole pressure analysis and pressure and rate transient analysis.

Internal Control and Qualifications of Third Party Engineers and Internal Staff. The technical personnel responsible for preparing the reserve estimates at NSAI 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. NSAI is an independent firm of petroleum engineers, geologists, geophysicists, and petrophysicists; the firm does not own an interest in McMoRan's properties and is not employed on a contingent fee basis. McMoRan's internal staff of petroleum engineers and geoscience professionals work closely with its independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to NSAI in their reserve estimation process. Throughout each fiscal year, McMoRan's technical staff meets with representatives of NSAI to review properties and discuss methods and assumptions used in preparation of the proved reserves estimates. McMoRan provides historical information to NSAI, including ownership interest, natural gas production, well test data, commodity prices and operating and development costs. The NSAI reserve report is reviewed with representatives of NSAI and McMoRan's internal technical staff before dissemination of the information. Additionally, McMoRan's senior management reviews the NSAI reserve report.

The internal reservoir engineering staff is supervised by FM O&G's Vice President of Operations, who has 37 years of technical experience in petroleum engineering and reservoir evaluation and analysis. This individual directs the activities of its internal reservoir engineering staff for the internal reserve estimation process and also to provide the appropriate data to NSAI for the year-end natural gas reserves estimation process. The preparation of proved natural gas reserve estimates are completed in accordance with McMoRan's internal control procedures. These procedures, which are intended to ensure reliability of reserve estimations, include (i) the review and verification of historical production data, (ii) the review by FM O&G's Vice President of Operations of annually reported proved reserves, including the review of significant reserve changes and new proved undeveloped reserves additions, if any, (iii) the verification of property ownership by McMoRan’s land department; and (iv) none of McMoRan's employee’s compensation being tied to the amount of reserves reported.

Proved Reserves. Proved reserve volumes attributable to the subject interests have been determined in accordance with SEC guidelines, which require the use of an average price, calculated as the twelve-month historical 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. The reference price for reserve determination is the Henry Hub spot price for natural gas, which was $3.10 per million British thermal units (MMBtu) as of December 31, 2018. The price is held constant throughout the life of the property, except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual escalations. In accordance with the guidelines, the average realized price used in McMoRan's reserve reports as of December 31, 2018, was $2.98 per Mcf of natural gas. All of the natural gas reserves attributable to the subject interests are located in the U.S. There were no oil reserves as of December 31, 2018.

The scope and results of procedures employed by NSAI are summarized in their reserve report. For purposes of reserve estimation, McMoRan and NSAI use technical and economic data including well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. McMoRan's 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 NSAI considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. 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 natural gas that McMoRan or HOGA ultimately recovers.

Proved reserves represent quantities of 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 natural gas actually recovered will equal or exceed the estimate. The following table presents estimated proved reserves attributable to the subject interests as of December 31, 2018:

	Natural Gas (MMcf)
Proved developed	1,376
Proved undeveloped	—
Total proved reserves	1,376

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, 2018.

Estimated undiscounted future net cash flows before income taxes	$3,531,100
Present value of estimated future net cash flows before income taxes (PV-10) [(a), (b)]	$3,132,300
Discounted future income taxes [(c)]	—
Standardized measure (See Note 9)	$3,132,300

(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. The reference price as of December 31, 2018, was $3.10 per MMBtu of natural gas. These prices are held constant throughout the life of the natural 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 price used in the Royalty Trust reserve report as of December 31, 2018, was $2.98 per Mcf of natural gas. The Royalty Trust's reference prices are the Henry Hub spot price for natural gas.

(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 GAAP and is not intended to represent the current market value of our estimated natural gas reserves. PV-10 should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP. See Note 9 to the Notes to Financial Statements located in Part II, Item 8. “Financial Statements and Supplementary Data” of this Form 10-K.

(c) For tax reporting purposes, the Royalty Trust is considered a non-taxable "pass-through" entity, see Note 4 to the Notes to Financial Statements located in Part II, Item 8. “Financial Statements and Supplementary Data” of this Form 10-K.

Refer to Note 8 to the Notes to Financial Statements located in Part II, Item 8. “Financial Statements and Supplementary Data” of this Form 10-K for further discussion of proved reserves.

Production and Productive Well Interests. As of December 31, 2018, only the onshore Highlander subject interest had established commercial production, which began on February 25, 2015. Prior to this date there had been no commercial production of hydrocarbons from any of the subject interests. During the year ended December 31, 2018, the Royalty Trust received royalties of $1,462,796 from McMoRan related to 576,120 Mcf of natural gas production attributable to the onshore Highlander subject interest with average post-production costs of $0.31 per Mcf and an average receipt price of $2.85 per Mcf. During the year ended December 31, 2017, the Royalty Trust received royalties of $1,376,758 from McMoRan related to 525,972 Mcf of natural gas production attributable to the onshore Highlander subject interest with average post-production costs of $0.30 per Mcf and an average receipt price of $2.91 per Mcf.

REGULATION

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

General. McMoRan’s and HOGA'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 and HOGA have 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 and HOGA'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 and HOGA's respective oil and natural 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 natural gas properties.

Federal Leases. As of December 31, 2018, there is one offshore lease located in federal waters on the Gulf of Mexico’s outer continental shelf relating to the subject interests. McMoRan has informed the Trustee that it does not plan to develop or further develop the subject interest associated with this lease.

Federal offshore leases are administered by the BOEM and the BSEE. The lease was obtained through competitive bidding, contains relatively standard terms and requires 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 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.

State and Local Regulation of Drilling and Production. Each of McMoRan and HOGA also owns interests in properties located in state waters of Louisiana and/or 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 oil and natural gas properties, and the levels of production from oil and natural gas wells.

On February 5, 2019, McMoRan completed the the Highlander Sale. The onshore Highlander subject interest was sold subject to the overriding royalty interest in future production held by the Royalty Trust. As a result of the Highlander Sale, HOGA has a 72 percent working interest and an approximate 49 percent net revenue interest in the onshore Highlander subject interest. The Royalty Trust continues to hold a 3.6 percent overriding royalty interest in the onshore Highlander subject interest. McMoRan will remain operator of the onshore Highlander subject interest during a transition period until HOGA qualifies and is designated as operator, which is expected to occur on or before May 31, 2019. McMoRan has informed the Trustee that it has no plans to pursue, has relinquished, has allowed to expire or has sold all of the subject interests. To the extent that McMoRan or HOGA do not fund the exploration and development of their respective subject interests, or if for any other reason sufficient production from the onshore Highlander subject interest is not maintained in commercial quantities, Royalty Trust unitholders will not realize any additional value from their investment in the royalty trust units.

Environmental Matters. McMoRan’s and HOGA's respective operations are subject to numerous laws relating to environmental protection. These laws impose substantial penalties for any pollution resulting from McMoRan’s or HOGA's operations. The Trustee has been advised by McMoRan and HOGA that McMoRan and HOGA believe that their respective operations comply with applicable laws, including environmental laws, in all material respects.

Solid Waste. McMoRan's and HOGA's operations require the disposal of both hazardous and non-hazardous solid wastes that are subject to the requirements of the Federal Resource Conservation and Recovery Act (RCRA) and comparable state statutes. Drilling fluids, produced waters and other wastes associated with the exploration, production and/or development of oil and natural gas, including naturally occurring radioactive material, if properly handled, are currently excluded from regulation as hazardous wastes under RCRA and, instead, are regulated under RCRA's less stringent non-hazardous waste requirements. Nevertheless, it is possible that these wastes could be classified as hazardous wastes in the future. For example, in December 2016, the EPA and environmental groups entered into a consent decree to address the EPA's alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production-related oil and natural gas wastes from regulation as hazardous wastes under RCRA. The consent decree requires the EPA to propose a rulemaking no later than March 15, 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and natural gas wastes or to sign a determination that revision of the regulations is not necessary, and complete any revisions to the applicable RCRA regulations no later than July 15, 2021. While the EPA has not yet taken any action toward changing the status of oil and natural gas wastes under RCRA, any change in the exclusion for such wastes could potentially result in an increase in McMoRan's and HOGA's respective costs to manage and dispose of those wastes.

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 or HOGA 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 or HOGA or both 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 and HOGA may be subject to cost recovery and to some other claims as a result of operations.

Air. McMoRan's and HOGA's operations are also subject to regulation of air emissions under the Federal Clean Air Act (CAA), comparable state and local requirements and the OCSLA.These laws and regulations may require pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, strict compliance with air permit requirements or the utilization of specific equipment or technologies to control emissions. The need to acquire such permits has the potential to delay or limit the development of oil and gas projects or require McMoRan and HOGA to incur certain capital expenditures for air pollution control equipment or other air emissions-related issues. For example, the EPA in 2012 adopted federal New Source Performance Standards (NSPS) that require the reduction of volatile organic compound emissions from certain fractured and refractured natural gas wells for which well completion operations are conducted and further require that most wells use reduced emission completions, also known as "green completions." These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, and from pneumatic controllers and storage vessels. In June 2016, the EPA published a final rule adopting additional NSPS requirements for new, modified, or reconstructed oil and gas facilities that require control of the greenhouse gas methane from affected facilities, including requirements to find and repair fugitive leaks of methane emissions at well sites (Methane Rule). Following the 2016 presidential election and change in administrations, in 2017 the EPA proposed to delay implementation of the Methane Rule, and also convened a reconsideration proceeding that resulted in two 2018 rulemaking projects aimed at rolling back certain Methane Rule requirements. These actions, like the Methane Rule itself, have been, or are likely to be, challenged in courts. The ultimate fate of the Methane Rule requirements is unclear. Nevertheless, regulations promulgated under the CAA may require McMoRan and HOGA to incur development expenses to install and utilize specific equipment, technologies, or work practices to control emissions from their respective operations.

The EPA also is charged with establishing ambient air quality standards, the implementation of which can indirectly impact McMoRan's and HOGA's respective operations. For example, in October 2015, the EPA lowered the National Ambient Air Quality Standard (NAAQS), for ozone from 75 to 70 parts per billion. A number of state and industry petitioners filed suit in the U.S. Court of Appeals for the District of Columbia Circuit, challenging the 2015 ozone NAAQS. The outcome of the litigation challenging the standard is unknown at this time. Although the EPA has designated all counties in which McMoRan and HOGA operate as attainment areas for the 2015 ozone standard, these determinations may be revised in the future. State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit the ability of McMoRan and HOGA to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant.

Compliance with these and other air pollution control and permitting requirements has the potential to increase McMoRan’s and HOGA’s respective production costs, which costs could be significant. Additionally, violations of lease conditions or regulations related to air emissions can result in civil and criminal penalties, as well as potential court injunctions curtailing operations and canceling leases. Such enforcement liabilities can result from either governmental or citizen enforcement.

Water. The Federal Clean Water Act (CWA) and analogous state laws and implementing regulations impose restrictions and strict controls regarding the discharge of pollutants into waters of the U.S. and waters of the states, respectively. Pursuant to these laws and regulations, the discharge of pollutants to regulated waters is prohibited unless it is permitted by the EPA, an analogous state or tribal agency, or both. HOGA does not presently discharge pollutants associated with the exploration, development and production of oil and natural gas on the onshore Highlander subject interest into federal or state waters. McMoRan discharges stormwater, domestic waste water, and treated sanitary waste water into state waters pursuant to a permit issued by the Louisiana Department of Environmental Quality in accordance with the National Pollutant Discharge Elimination System (NPDES) provisions of the CWA. The discharge of wastewater from most onshore oil and gas exploration and production activities is currently prohibited east of the 98^{th} meridian. Additionally, in June 2016, the EPA issued a final rule implementing wastewater pre-treatment standards that prohibit onshore unconventional oil and natural gas extraction facilities from sending wastewater directly to publicly owned treatment works (POTW). Unconventional extraction facilities can send wastewater to a private centralized wastewater treatment facility that can either discharge treated water or send it to a POTW. The EPA is conducting a study of the treatment and discharge of oil and natural gas wastewater.

The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers (ACE). CWA Section 401 provides that the applicant for an individual National Pollutant Discharge Elimination System (NPDES) permit to be issued by the EPA or an individual Section 404 permit to be issued by the ACE must notify the state in which the discharge will occur and provide an opportunity for the state to determine if the discharge will comply with the state's approved water quality program. In some instances this process could result in delay in issuance of the permit, more stringent permit requirements, or denial of the permit.

In September 2015, new EPA and ACE rules defining the scope of the "waters of the United States," and EPA's and the ACE's jurisdiction, became effective (2015 Rule). The 2015 Rule has been challenged in multiple courts on the grounds that it unlawfully expands the reach of CWA programs. Due to the status of pending litigation, the 2015 Rule is currently in effect in 22 states. In the remaining states, regulations in effect before promulgation of the 2015 Rule and guidance interpreting relevant U.S. Supreme Court rulings are in effect. On December 11, 2018, the heads of the EPA and ACE signed a proposed regulation that would revise the definition of waters of the U.S. to reduce its reach from the 2015 Rule (2018 Pre-Proposal Rule). The fates of the 2015 Rule and the 2018 Pre Proposal Rule and applicability of the rules during current and future litigation are uncertain; however, to the extent the 2015 Rule is in effect, it expands the scope of CWA jurisdiction, and McMoRan and HOGA could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas or other waters of the U.S.

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 facilities to meet the financial assurance obligations under the Oil Pollution Act.

Climate Change. In response to findings that emissions of carbon dioxide, methane and certain other greenhouse gases (GHGs) present an endangerment to public health and the environment, the EPA has issued regulations to restrict emissions of GHGs under existing provisions of the CAA. These regulations include limits on tailpipe emissions from motor vehicles, pre-construction and operating permit requirements for certain large stationary sources, and methane emissions standards for certain new, modified and reconstructed oil and gas sources. The

EPA also has adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including certain onshore oil and natural gas production facilities, on an annual basis.

In December 2015, the EPA finalized rules that added new sources to the scope of greenhouse gases monitoring and reporting rule. These new sources include gathering and boosting facilities. The revisions also include the addition of well identification reporting requirements for certain facilities. In addition, as described above, in June 2016 the EPA published a final rule that requires operators to reduce methane emissions from certain new, modified or reconstructed oil and gas facilities, including production, processing, transmission and storage activities (Methane Rule). Following the 2016 presidential election and change in administrations, in 2017 the EPA proposed to delay implementation of the Methane Rule and also convened a reconsideration proceeding that resulted in two 2018 rulemaking projects aimed at rolling back certain Methane Rule requirements. These actions, like the Methane Rule itself, have been, or are likely to be, challenged in courts. The ultimate fate of the Methane Rule requirements is unclear. Nevertheless, regulations promulgated under the CAA may require McMoRan or HOGA to incur development expenses to install and utilize specific equipment, technologies, or work practices to control GHG emissions from their operations, which could adversely affect McMoRan’s or HOGA’s operations.

In addition, from time to time the U.S. Congress has considered legislation to reduce emissions of GHGs, and many of the states have already taken legal measures to reduce GHG emissions, primarily through the implementation of state and/or regional GHG cap-and-trade programs. Most of these cap-and-trade programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal. The adoption of any legislation or regulations imposing reporting obligations on McMoRan and HOGA equipment and operations, limiting emissions of GHGs from McMoRan and HOGA equipment and operations, or requiring McMoRan and HOGA to acquire emission allowances or credits, could require additional costs to be incurred by McMoRan and HOGA or inhibit or delay operations or expansion efforts.

On an international level, the U.S. is one of almost 200 nations that agreed in December 2015 to an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and disclose the measures each country will use to achieve its GHG emissions targets (the Paris Agreement). However, the Paris Agreement does not impose any binding obligations on the U.S. Moreover, in June 2017, President Trump announced that the U.S. would withdraw from the Paris Agreement, but may enter into a future international agreement related to GHGs. In August 2017, the U.S. State Department officially informed the United Nations of the intent of the U.S. to withdraw from the Paris Agreement. Such withdrawal has not yet been finalized, and whether the U.S. may reenter the Paris Agreement or a separately negotiated agreement is unclear at this time. The adoption and implementation of any laws or regulations imposing reporting obligations on, or limiting emissions of GHG from operations could require additional costs incurred to reduce emissions of GHGs associated with operations or could adversely affect demand for the oil, natural gas and NGL production attributable to the overriding royalty interests, and thus possibly have a material adverse effect on the Royalty Trust’s revenues. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and natural gas will continue to represent a substantial percentage of global energy use over that time. Finally, to the extent increasing concentrations of GHGs in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events, such events could have an adverse effect on assets and operations related to the subject interests.

Endangered Species. The federal Endangered Species Act and similar state statutes 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 and HOGA's exploration, development, and production operations and impose civil or criminal penalties for noncompliance.

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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 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 and HOGA'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.
Additionally, future price fluctuations for natural gas will directly affect the amount of distributions to Royalty Trust unitholders and will also affect estimates of reserves attributable to the overriding royalty interests and estimated and actual future net revenues of the Royalty Trust. None of McMoRan, HOGA or the Royalty Trust can make reliable predictions of future natural gas supply and demand or future product prices. For more information regarding risks associated with natural 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 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

The following is a summary of certain U.S. federal income tax matters that may be relevant to the Royalty Trust unitholders. This summary is based upon current provisions of the Internal Revenue Code of 1986, as amended (the Code), existing and proposed Treasury regulations thereunder and current administrative rulings and court decisions, all of which are subject to changes that may or may not be retroactively applied. No attempt has been made in the following summary to comment on all U.S. federal income tax matters affecting the Royalty Trust or the Royalty Trust unitholders.
The summary has limited application to non-U.S. persons and persons subject to special tax treatment such as, without limitation: banks, insurance companies or other financial institutions; Royalty Trust unitholders subject to the alternative minimum tax; tax-exempt organizations; dealers in securities or commodities; regulated investment companies; real estate investment trusts; traders in securities that elect to use a mark-to-market method of accounting for their securities holdings; non-U.S. Royalty Trust unitholders that are “controlled foreign corporations” or “passive foreign investment companies”; persons that are S-corporations, partnerships or other pass-through entities; persons that own their interest in the Royalty Trust Units through S-corporations, partnerships or other pass-through entities; persons that at any time own more than 5% of the aggregate fair market value of the Royalty Trust Units; expatriates and certain former citizens or long-term residents of the U.S.; U.S. Royalty Trust unitholders whose functional currency is not the U.S. dollar; persons who hold the Royalty Trust Units as a position in a hedging transaction, “straddle”, “conversion transaction” or other risk reduction transaction; or persons deemed to sell the Royalty Trust Units

under the constructive sale provisions of the Code. Each Royalty Trust unitholder should consult his own tax advisor with respect to his particular circumstances.

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.

The Tax Cuts and Jobs Act (the TCJA) enacted on December 22, 2017, includes significant modifications to existing U.S. tax laws, including changes to the corporate and individual tax rates. Royalty Trust unitholders should consult their own tax advisors regarding the impact of the TCJA on the income, gain, loss or deduction derived by the unitholder for the Royalty Trust.

The income of the Royalty Trust consists primarily of royalties equal to a specified share of the proceeds of oil and gas produced from exploration prospects. The deductions of the Royalty Trust consist of administrative expenses. Each Royalty Trust unitholder is entitled to depletion deductions because the royalties are expected to constitute “economic interests” in oil and gas properties for U.S. federal income tax purposes. The rules with respect to the depletion allowance are complex and must be computed separately by each Royalty Trust unitholder and not by the Royalty Trust. Royalty Trust unitholders should consult their own tax advisors regarding the availability of depletion deductions.

If a taxpayer disposes of any “Section 1254 property” (certain oil, gas, geothermal or other mineral property), and if the adjusted basis of such property includes adjustments for deductions for depletion under Section 611 of the Code, the taxpayer generally must recapture the amount deducted for depletion as ordinary income (to the extent of gain realized on such disposition).

The classification of the Trust’s income for purposes of the passive loss rules may be important to a Royalty Trust unitholder. Royalty income generally is treated as portfolio income and does not offset passive losses. Therefore, in general, Royalty Trust unitholders should not consider the taxable income from the Trust to be passive income in determining net passive income or loss.

Under the TCJA, for tax years beginning after December 31, 2017 and before January 1, 2026, the highest marginal U.S. federal income tax rate applicable to ordinary income of individuals is 37%, and the highest marginal U.S. federal income tax rate applicable to long-term capital gains (generally, gains from the sale or exchange of certain investment assets held for more than one year) and qualified dividends of individuals is 20%. Under the TCJA, for such tax years, personal exemptions and miscellaneous itemized deductions are not allowed. For such tax years, the U.S. federal income tax rate applicable to corporations is 21%, and such rate applies to both ordinary income and capital gains.

Section 1411 of the Code imposes a 3.8% Medicare tax on certain investment income earned by individuals, estates, and trusts. For these purposes, investment income generally will include a Royalty Trust unitholder’s allocable share of the Royalty Trust’s interest and royalty income plus the gain recognized from a sale of units. In the case of an individual, the tax is imposed on the lesser of (i) the individual’s net investment income from all investments, or (ii) the amount by which the individual’s modified adjusted gross income exceeds specified threshold levels depending on such individual’s federal income tax filing status. In the case of an estate or trust, the tax is imposed on the lesser of (i) undistributed net investment income, or (ii) the excess adjusted gross income over the dollar amount at which the highest income tax bracket applicable to an estate or trust begins. The tax consequences to a Royalty Trust unitholder of the acquisition, ownership or disposition of units will depend in part on the Royalty Trust unitholder’s tax circumstances. Royalty Trust unitholders should consult their tax advisors regarding the U.S. federal income tax consequences relating to acquiring, owning or disposing the Royalty Trust units.

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 2018 U.S. 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. As a result, 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.

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. However, in 2015, the Louisiana legislature reduced the available depletion deduction by 28% through June 2018, and is considering extending the reduction beyond such date. 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.

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.

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 15, 2019, only the onshore Highlander subject interest has any reserves classified as proved, probable or possible and has established commercial production.

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 15, 2019, only the onshore Highlander subject interest has any reserves classified as proved, probable or possible and has established commercial production. Other than the onshore Highlander subject interest, whose well began commercial production on February 25, 2015, the subject interests remain "exploration concepts." As McMoRan reported to the Trustee, McMoRan has no plans to pursue, has relinquished, has allowed to expire or has sold all of the subject interests.

The Royalty Trust has no ability to direct or influence the exploration or development of the subject interests. In addition, none of FCX, McMoRan or HOGA is under any obligation to fund or to commit any resources to the exploration or development of the subject interests.

To the extent that McMoRan or HOGA does not fund the exploration and development of their respective subject interests, or if for any other reason sufficient production from the subject interests is not maintained in commercial quantities, Royalty Trust unitholders will not realize any additional value from their investment in the royalty trust units.

Future Royalty Trust distributions are uncertain because the Royalty Trust does not control the operations of the subject interests and any royalties received must exceed administrative expenses, any indebtedness and a minimum cash requirement.

The Royalty Trust has no control over the operations of the subject interests, which are necessary to generate any royalties to be distributed to the unitholders. In addition, any royalties received by the Royalty Trust must first be used to (i) satisfy Royalty Trust administrative expenses and (ii) reduce Royalty Trust indebtedness. Lastly, the Trustee has established a minimum cash reserve of $250,000. As a result, distributions will be made to Royalty Trust unitholders only when royalties received less administrative expenses incurred and repayment of all indebtedness exceeds the $250,000 minimum cash reserve.

Even though distributions were paid to Royalty Trust unitholders in 2017 and 2018, and have been declared so far in 2019, distributions may not necessarily be made in the future. The Royalty Trust's only other sources of liquidity are mandatory annual contributions, any loans and the required standby reserve account or letter of credit from FCX. As a result, any material adverse change in FCX's or McMoRan's financial condition or results of operations could materially and adversely affect the Royalty Trust and the royalty trust units.

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

Natural 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, natural gas, as well as perceptions of supply of, and demand for, natural gas;
- U.S. and worldwide political and economic conditions;

- weather conditions and seasonal trends;
- anticipated future prices of 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 2018, the New York Mercantile Exchange (NYMEX) natural gas price fluctuated from a low of $2.53 per MMBtu to a high of $4.93 per MMBtu and the West Texas Intermediate (WTI) crude oil price ranged from a low of $42.36 per barrel to a high of $76.90 per barrel. During the first quarter of 2019, natural gas prices have averaged $2.89 per MMBtu and on March 15, 2019, the NYMEX natural gas price was $2.80 per MMBtu. On March 15, 2019, the WTI crude oil price per barrel was $58.52. Royalties that the Royalty Trust receives from its share of production will be reduced as a result of lower natural gas prices. As a result, future distributions from the Royalty Trust to its unitholders could be reduced or discontinued. In addition, lower oil and natural gas prices reduce the likelihood that the subject interests will be developed or that any oil or natural gas discovered will be economic to produce. 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 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 and HOGA's respective Inboard Lower Tertiary/Cretaceous exploration prospects target formations in the shallow waters 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.

There is a limited public market for the royalty trust units, which could affect the market price, trading volume, liquidity and resale price of the royalty trust units.

The royalty trust units are quoted on the OTC Pink tier of the OTC markets. The OTC Pink is a significantly more limited market than the national securities exchanges, which could adversely affect the market price, trading volume, liquidity and resale price of the royalty trust units.

Although the royalty trust units are currently quoted on the OTC Pink, an active market in the royalty trust units may not continue at present levels or increase in the future. In addition, securities that trade on the OTC Pink experience more volatility compared to securities that trade on a national securities exchange. This volatility may be caused by a variety of factors, including the lack of readily available price quotations, the absence of consistent administrative supervision of bid and ask quotations, lower trading volumes, and market conditions.

Because there is a limited public market for the royalty trust units, the market price and trading volume of the royalty trust units may be volatile.

Additionally, the royalty trust units could become subject to the SEC's "penny stock" regulations. The SEC defines a "penny stock" as any equity security that has a market price of less than $5.00 per share subject to certain exceptions, including securities of issuers with net tangible assets in excess of $2.0 million that have been in continuous operation for at least three years. The Royalty Trust had approximately $2.8 million in net tangible assets at December 31, 2018. If the royalty trust units become subject to the SEC's penny stock regulations, brokers may be less willing to execute transactions in the royalty trust units as a result of the requirements imposed by these regulations, which could further limit the liquidity of the royalty trust units. The closing bid price for the royalty trust units was $0.03 on March 15, 2019.

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:

- as a result of other risk factors discussed in this Form 10-K;
- the failure of the subject interests to produce hydrocarbons;
- decisions by McMoRan or HOGA to delay or not to pursue the exploration or development of some or all of their respective 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 or HOGA; 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. This call right could impose a ceiling on the price of the royalty trust units. In addition, 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 following the end of such nine-month period. The volume-weighted average price per royalty trust unit was $0.05 for the nine-month period ended March 15, 2019. 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 by a holder from the resale of its royalty trust units.

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 having proved, probable or possible reserves and have potential well locations 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 on the date on which this Form 10-K was filed, the Royalty Trust continues 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 Royalty Trust were treated for U.S. federal income tax purposes as a partnership, it likely would be subject to new audit procedures that for taxable years beginning after December 31, 2017, alter the procedures for auditing large partnerships and also alters the procedures for assessing and collecting income taxes due (including applicable penalties and interest) as a result of an audit. These rules effectively would impose an entity level tax on the Royalty Trust, and unitholders may have to bear the expense of the adjustment even if they were not Royalty Trust unitholders during the audited taxable year.

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.

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 natural 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 for both U.S. federal income tax and state income tax purposes.

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 and elects to report using the de minimis test, 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. Although 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. The Royalty Trust does not maintain any type of insurance against any of the risks of conducting oil and gas exploration and production or related activities.

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 dependent on FCX for funding unless royalty income from production on the subject interests is sufficient to cover the Royalty Trust's 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. No such contributions were made during the years ended December 31, 2018 and 2017. 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. Since inception, FCX has loaned $650,000 to the Royalty Trust under this arrangement, all of which had been repaid prior to December 31, 2018, including $500,000 during 2017, and no amounts were outstanding at December 31, 2018. All funds the Trustee borrows to cover expenses or liabilities, whether from FCX or from any other source, must be repaid before the Royalty Trust unitholders will receive any distributions.

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 if its funds are inadequate 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. As of December 31, 2018, the Royalty Trust had not drawn any funds from the reserve account, and FCX had not requested a reduction of such reserve account. If FCX requested and the Royalty Trust consented to reduce the current $1.0 million reserve cash fund, the Royalty Trust's ability to fund ongoing administrative expenses could be adversely affected.

Additionally, if any material adverse change in FCX's, McMoRan's or HOGA's financial condition or results of operations causes McMoRan or HOGA to be unable to fund the exploration and development of the subject interests, or if for any other reason sufficient production from the onshore Highlander subject interest is not maintained in commercial quantities, Royalty Trust unitholders will not realize any additional value from their investment in the royalty trust units.

Climate change laws and regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the oil and natural gas that McMoRan or HOGA produces while the physical effects of climate change could disrupt their production and cause it to incur significant costs in preparing for or responding to those effects.

In response to findings that emissions of carbon dioxide, methane and certain other greenhouse gases (GHGs) present an endangerment to public health and the environment, the EPA has issued regulations to restrict emissions of GHGs under existing provisions of the Clean Air Act. These regulations include limits on tailpipe emissions from motor vehicles and pre-construction and operating permit requirements for certain large stationary sources. The EPA also has adopted rules requiring the reporting of greenhouse gas emissions from specified large GHG emission sources in the U.S., including certain onshore oil and natural gas production facilities, on an annual basis. In addition, in 2016 the EPA adopted federal New Source Performance Standards (NSPS) for new, modified, or reconstructed oil and gas facilities that require control of the greenhouse gas methane from affected facilities, including requirements to find and repair fugitive leaks of methane emissions at well sites (the Methane Rule). Following the 2016 presidential election and change in administrations, in 2017 the EPA proposed to delay implementation of the Methane Rule and also convened a reconsideration proceeding that resulted in two 2018 rulemaking projects aimed at rolling back certain Methane Rule requirements. These actions, like the Methane Rule itself, have been, or are likely to be, challenged in courts. The ultimate fate of the Methane Rule requirements is unclear. Nevertheless, regulations promulgated under the Clean Air Act may require McMoRan or HOGA to incur development expenses to install and utilize specific equipment, technologies, or work practices to control GHG emissions from their operations, which could adversely affect McMoRan’s or HOGA’s operations.

In addition, from time to time the U.S. Congress has considered legislation to reduce emissions of GHGs, and many of the states have already taken legal measures to reduce GHG emissions, primarily through the implementation of state and/or regional GHG cap-and-trade programs. Most of these cap-and-trade programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal. The adoption of any legislation or regulations imposing reporting obligations on McMoRan and HOGA equipment and operations, limiting emissions of GHGs from McMoRan and HOGA equipment and operations, or requiring McMoRan and HOGA to acquire emission allowances or credits, could require additional costs to be incurred by McMoRan and HOGA or inhibit or delay operations or expansion efforts.

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

Because of FCX's focus on its copper resources, 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. McMoRan has informed the Trustee that it has no plans to pursue, has relinquished, has allowed to expire or has sold all of the subject interests.

McMoRan may at any time transfer all or part of the subject interests and will not have control or influence over the activities related to the subject interests it does not operate.

McMoRan 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. Unless McMoRan and the transferee agree otherwise, the transferee would be responsible for all of McMoRan's obligations relating to the overriding royalty interests on the portion of the subject interests transferred, and McMoRan would have no continuing obligation to the Royalty Trust for those subject interests.

On February 5, 2019, McMoRan completed the sale of all of its rights, title and interest in and to the onshore Highlander subject interest pursuant to a purchase and sale agreement with HOGA. The onshore Highlander subject interest was sold subject to the overriding royalty interest in future production held by the Royalty Trust. As a result of the Highlander Sale, HOGA has a 72 percent working interest and an approximate 49 percent net revenue interest in the onshore Highlander subject interest. The Royalty Trust continues to hold a 3.6 percent overriding royalty interest in the onshore Highlander subject interest. McMoRan will remain operator of the onshore Highlander subject interest during a transition period until HOGA qualifies and is designated as operator, which is expected to occur on or before May 31, 2019. McMoRan has informed the Trustee that it has no plans to pursue, has relinquished, has allowed to expire or has sold all of the 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.

The Royalty Trust will dissolve on the earliest to occur 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 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. In addition, 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 following the end of such nine-month period. The volume-weighted average price per royalty trust unit was $0.05 for the nine-month period ended March 15, 2019.

The Royalty Trust is passive in nature and neither the Royalty Trust nor the Royalty Trust unitholders have any ability to influence FCX, McMoRan or HOGA 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, McMoRan or HOGA and, therefore, have no managerial, contractual or other ability to influence their activities or the development or operations of the subject interests. Additionally, none of FCX, McMoRan or HOGA is under any obligation to fund or to commit any resources to the exploration or development of the subject interests.

FCX or HOGA may sell royalty trust units in the public or private markets, and any such sales may have a material adverse effect on the trading price of the royalty trust units.
At December 31, 2018, FCX, through its wholly owned subsidiary McMoRan, held 62,286,299 royalty trust units (or 27.1% of the outstanding royalty trust units). In connection with the Highlander Sale on February 5, 2019, McMoRan assigned 31,143,150 royalty trust units to HOGA. FCX or HOGA may sell royalty trust units in the public or private markets. Any such sales may 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 also may 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 affirmative vote of 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 and HOGA so long as each holds a significant percentage of the total royalty trust units.
Cybersecurity incidents or other failures in telecommunications or information technology systems could result in information theft, data corruption and significant disruption of the respective operations of the Trustee, HOGA and McMoRan as they relate to the Royalty Trust.
Each of the Trustee, HOGA and McMoRan depend heavily upon information technology systems and networks in connection with their respective business activities as they relate to the Royalty Trust. Despite any security measures implemented, events such as the loss or theft of back-up tapes or other data storage media could occur, and computer systems could be subject to physical and electronic break-ins, cyber-attacks and similar disruptions from unauthorized tampering, including threats that may come from external factors, such as governments, organized crime, hackers and third parties to whom certain functions are outsourced, or may originate internally from within the respective companies.
If a cybersecurity incident were to occur, it could potentially jeopardize the confidential, proprietary and other information processed and stored in, and transmitted through, the computer systems and networks of the respective companies, or otherwise cause interruptions or malfunctions in the operations of the Royalty Trust, which could result in litigation, increased costs and regulatory penalties. Despite any steps taken by the respective companies to prevent and detect such attacks, it is possible that a cyber incident will not be discovered for some time after it occurs, which could increase exposure to these consequences.
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.

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 are quoted on the OTC Pink tier of the over-the-counter, or OTC, markets under the symbol "GULTU". For information regarding the OTC Pink and fluctuations in the market price and trading volume of the royalty trust units, see Part I, Item 1A. "Risk Factors - There is a limited public market for the royalty trust units, which could affect the market price, trading volume, liquidity and resale price of the royalty trust units" of this Form 10-K.

As of February 28, 2019, there were 230,172,696 royalty trust units outstanding and 4,780 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, 2018. At December 31, 2018, FCX, through its wholly owned subsidiary McMoRan, held 62,286,299 royalty trust units (or 27.1% of the outstanding royalty trust units). In connection with the Highlander Sale on February 5, 2019, McMoRan assigned 31,143,150 royalty trust units to HOGA.

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

As a smaller reporting company as defined in Item 10(f) of Regulation S-K, the Royalty Trust is not required to provide the information required by this Item.

Item 7. Trustee’s Discussion and Analysis of Financial Condition and Results of Operations

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 51. Additionally, please refer to the section above entitled “Forward-Looking Statements" in this Form 10-K. 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 oil and gas assets are held through its wholly owned subsidiary, FCX Oil & Gas LLC (FM O&G). As a result of the merger, MMR and McMoRan are both indirect wholly owned subsidiaries of FM O&G.

The Royalty Trust is a statutory trust created as contemplated by the merger agreement 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 Inboard Lower Tertiary/Cretaceous exploration prospects located in the shallow waters 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 acquired by FCX pursuant to the merger and were not considered part of FCX's purchase consideration of MMR.

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 interests (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, (d) its repayment of loans from FCX, (e) its receipt of the conveyance of the overriding royalty interests from McMoRan pursuant to the master conveyance, (f) its receipt of royalties from McMoRan, and (g) its cash distributions to unitholders, if any, 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.

McMoRan previously informed the Trustee that 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 geologic trend. McMoRan believes that data from nine 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. Eight of these wells were included in the subject interests, along with additional exploration prospects that will also be burdened by the overriding royalty interests. On February 5, 2019, McMoRan completed the sale of all of its rights, title and interest in and to the onshore Highlander subject interest pursuant to a purchase and sale agreement with Highlander Oil & Gas Assets LLC (HOGA) (the Highlander Sale). The onshore Highlander subject interest was sold subject to the overriding royalty interest in future production held by the Royalty Trust. As a result of the Highlander Sale, HOGA has a 72 percent working interest and an approximate 49 percent net revenue interest in the onshore Highlander subject interest. The Royalty Trust continues to hold a 3.6 percent overriding royalty interest in the onshore Highlander subject interest. McMoRan will remain operator of the onshore Highlander subject interest during a transition period until HOGA qualifies and is designated as operator, which is expected to occur on or before May 31, 2019. McMoRan has informed the Trustee that it has no plans to pursue, has relinquished, has allowed to expire or has sold all of the subject interests.

Currently, only the onshore Highlander subject interest has any reserves classified as proved, probable or possible and has established commercial production. The Royalty Trust has no ability to direct or influence the exploration or development of the subject interests. In addition, none of FCX, McMoRan or HOGA is under any obligation to fund or to commit any other resources to the exploration or development of the subject interests. To the extent that neither McMoRan nor HOGA funds the exploration and development of their respective subject interests, or if for any other reason sufficient production from the onshore Highlander subject interest is not maintained in commercial quantities, Royalty Trust unitholders will not realize any additional value from their investment in the royalty trust units.

The royalty trust units are quoted on the OTC Pink tier of the OTC markets. The OTC Pink is a significantly more limited market than the national securities exchanges, which could adversely affect the market price, trading volume, liquidity and resale price of the royalty trust units.
The closing bid price for the royalty trust units was $0.03 on March 15, 2019. For information regarding the OTC Pink, see Part I, Item IA. "Risk Factors - There is a limited public market for the royalty trust units, which could affect the market price, trading volume and resale price of the royalty trust units" of this Form 10-K.
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 2009 through March 15, 2019, the NYMEX natural gas price fluctuated from a low of $1.61 per MMBtu in 2016 to a high of $6.49 per MMBtu in 2014 and the WTI crude oil price ranged from a low of $26.05 per barrel in 2016 to a high of $114.83 per barrel in 2011. During 2018, the NYMEX natural gas price fluctuated from a low of $2.53 per MMBtu to a high of $4.93 per MMBtu and the WTI crude oil price ranged from a low of $42.36 per barrel to a high of $76.90 per barrel. On December 31, 2018, the NYMEX natural gas price was $2.94 per MMBtu and the WTI crude oil price was $45.41 per barrel. During the first quarter of 2019, natural gas prices have averaged $2.89 per MMBtu, and on March 15, 2019, the NYMEX natural gas price was $2.80 per MMBtu. On March 15, 2019, the WTI crude oil price per barrel was $58.52. Crude oil and natural gas prices are affected by numerous factors beyond either McMoRan's or HOGA'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 2009 through March 15, 2019.

OPERATIONAL ACTIVITIES

Oil and Gas Activities
For additional information regarding McMoRan's and HOGA'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
For information regarding McMoRan's production, see "Results of Operations" in this section of this Form 10-K.

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

Royalty Income. 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. As of December 31, 2018, only the onshore Highlander subject interest had established commercial production. During the year ended December 31, 2018, the Royalty Trust received royalties of $1,462,796 from McMoRan related to 576,120 Mcf of natural gas production attributable to the onshore Highlander subject interest with average post-production costs of $0.31 per Mcf and an average receipt price of $2.85 per Mcf. During the year ended December 31, 2017, the Royalty Trust received royalties of $1,376,758 from McMoRan related to 525,972 Mcf of natural gas production attributable to the onshore Highlander subject interest with average post-production costs of $0.30 per Mcf and an average receipt price of $2.91 per Mcf. Higher royalty income in 2018 as compared to 2017 is primarily due to increased production from the installation of a second pipeline from the onshore Highlander subject interest allowing for higher production volumes, partially offset by lower natural gas prices during 2018.

Administrative Expenses. For the years ended December 31, 2018 and 2017, the Royalty Trust paid administrative expenses of $630,551 and $534,085, respectively. Administrative expenses, which consisted primarily of audit, legal and trustee expenses incurred in connection with the administration of the Royalty Trust, were higher in 2018 as compared to 2017 primarily because of increased regulatory compliance costs as well as timing of payments for professional fees.

LIQUIDITY AND CAPITAL RESOURCES

Pursuant to the royalty trust agreement, FCX has agreed to pay annual trust expenses up to $350,000, with no right of repayment or interest due, to the extent the Royalty Trust lacks sufficient funds to pay administrative expenses. No such contributions were made during the years ended December 31, 2018 or 2017. 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. Since inception, FCX has loaned $650,000 to the Royalty Trust under this arrangement, all of which had been repaid prior to December 31, 2018, including $500,000 during 2017, and no amounts were outstanding at December 31, 2018. All funds the Trustee borrows to cover expenses or liabilities, whether from FCX or from any other source, must be repaid before the Royalty Trust unitholders will receive any distributions.

Pursuant to the royalty trust agreement, FCX 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 if its funds are inadequate 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. As of December 31, 2018, the Royalty Trust had not drawn any funds from the reserve account, and FCX had not requested a reduction of such reserve account.

As of December 31, 2018, only the onshore Highlander subject interest had established commercial production. Royalties are paid to the Royalty Trust on the last day of the month following the month in which production payments are received by McMoRan in accordance with the terms of the master conveyance. In accordance with the master conveyance, the Royalty Trust received royalties from McMoRan of $1,462,796 and $1,376,758 during the years ended December 31, 2018 and 2017, respectively, due to production from the onshore Highlander subject interest.

Royalties received by the Royalty Trust must first be used to (i) satisfy Royalty Trust administrative expenses and (ii) reduce Royalty Trust indebtedness. The Royalty Trust had no indebtedness outstanding as of December 31, 2018. Additionally, the Trustee has established a minimum cash reserve of $250,000. As a result, distributions will be made to Royalty Trust unitholders only when royalties received less administrative expenses incurred and repayment of any indebtedness exceeds the $250,000 minimum cash reserve. Distributable income totaled $838,155 and $356,486 for the years ended December 31, 2018 and 2017. On January 17, 2019, the Royalty Trust declared a cash distribution of $0.001108 per unit payable on February 13, 2019, to unitholders of record on January 30, 2019. These distributions are not necessarily indicative of future distributions. The Royalty Trust's only other sources of liquidity are mandatory annual contributions, any loans and the required standby reserve account or letter of credit from FCX. As a result, any material adverse change in FCX's, McMoRan's or HOGA's financial condition or results of operations could materially and adversely affect the Royalty Trust and the underlying royalty trust units. See Part I, Item 1A. “Risk Factors” of this Form 10-K for more information.

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.

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 GAAP. This other comprehensive basis of accounting corresponds to the accounting permitted for royalty trusts by the SEC.

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 carrying value of the Royalty Trust’s overriding royalty interests in the subject interests (defined in Note 2 to the Notes to Financial Statements located in Part II, Item 8. “Financial Statements and Supplementary Data” of this Form 10-K) is 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 is charged directly to the Trust Corpus as royalties are received, and does 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. If an impairment event occurs and it is determined that the carrying value of the Royalty Trust's overriding royalty interests in the subject interests may not be recoverable, an impairment will be recognized as measured by the amount by which the carrying amount of the overriding royalty interests in the subject interests exceeds the fair value of these assets, which would be measured by discounting projected cash flows. The related impairment amounts are recorded as a reduction to the overriding royalty interests with an offsetting reduction to the Trust Corpus in the period such impairment is determined, see Note 3. No impairment charges were recorded during the years ended December 31, 2018 and 2017.

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 7A. Quantitative and Qualitative Disclosures About Market Risk

As a smaller reporting company as defined in Item 10(f) of Regulation S-K, the Royalty Trust is not required to provide the information required by this Item.

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:

Opinion on the Financial Statements

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, 2018 and 2017, the related statements of distributable income and changes in trust corpus for each of the two years in the period ended December 31, 2018, and the related notes (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the assets, liabilities and trust corpus of the Royalty Trust at December 31, 2018 and 2017, and the distributable income for each of the two years in the period ended December 31, 2018, in conformity with modified cash basis of accounting described in Note 1.

Basis of Accounting

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

Basis for Opinion

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 the Royalty Trust's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Royalty Trust in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Royalty Trust is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Royalty Trust's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP

We have served as the Royalty Trust's auditor since 2013.

New Orleans, Louisiana
March 21, 2019

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

	December 31,	
	2018	2017
ASSETS		
Operating cash	$505,019	$457,331
Reserve fund cash	1,024,846	2,088
Reserve fund short-term investments	—	1,004,236
Overriding royalty interests in subject interests, net	1,295,598	1,995,048
Total assets	$2,825,463	$3,458,703
LIABILITIES AND TRUST CORPUS		
Reserve fund liability	$1,024,846	$1,006,324
Trust corpus (230,172,696 royalty trust units authorized, issued and outstanding as of December 31, 2018 and 2017)	1,800,617	2,452,379
Total liabilities and trust corpus	$2,825,463	$3,458,703

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,	
	2018	2017
Royalty income	$1,462,796	$1,376,758
Interest income and other	5,910	2,276
Administrative expenses	(630,551)	(534,085)
Income in excess of administrative expenses	$838,155	$844,949
Distributable income	$838,155	$356,486
Distributable income per royalty trust unit	$0.003641	$0.001549
Royalty trust units outstanding at end of year	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,	
	2018	2017
Trust corpus, beginning of period	$2,452,379	$3,507,430
Amortization of overriding royalty interests in subject interests	(699,450)	(1,750,845)
Income in excess of administrative expenses	838,155	844,949
Distributions paid	(790,467)	(149,155)
Trust corpus, end of period	$1,800,617	$2,452,379

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.

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 Royalty Trust's reserve fund short-term investments include U.S. treasury securities with maturities of three months to one year and are recorded at cost in accordance with the modified cash basis of accounting.

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 carrying value of the Royalty Trust’s overriding royalty interests in the subject interests (each defined in Note 2) is 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 is charged directly to the Trust Corpus as royalties are received, and will not affect distributable cash or the determination of distributable cash per royalty trust unit, see Note 3.

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 natural 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. If an impairment event occurs and it is determined that the carrying value of the Royalty Trust's overriding royalty interests in the subject interests may not be recoverable, an impairment will be recognized as measured by the amount by which the carrying amount of the overriding royalty interests in the subject interests exceeds the fair value of these assets, which would be measured by discounting projected cash flows. 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 of the carrying values of the overriding royalty interests in the subject interests involves a significant amount of judgment and may be subject to changes over time based on drilling plans and results, geophysical evaluations, the assignment of proved natural gas reserves, availability of capital and other factors. Fair value accounting guidance includes a hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 inputs) and the lowest priority to unobservable inputs (Level 3). When indicators of impairment are present and it is determined that the carrying value of the Royalty Trust's overriding royalty interests in the subject interests exceeds the estimated undiscounted cash flows of the subject interest, fair value estimates utilized in the impairment assessment are determined based on inputs not observable in the market and thus represent Level 3 measurements.

For the years ended December 31, 2018 and 2017, the Royalty Trust paid administrative expenses of $630,551 and $534,085, respectively. Administrative expenses, which consisted primarily of audit, legal and trustee expenses incurred in connection with the administration of the Royalty Trust, were higher in 2018 as compared to 2017 primarily because of increased regulatory compliance costs as well as timing of payments for professional fees.

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

The Royalty Trust is a statutory trust created as contemplated by the merger agreement 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 Inboard Lower Tertiary/Cretaceous exploration prospects located in the shallow waters 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 acquired by FCX pursuant to the merger and were not considered part of FCX's purchase consideration of MMR.

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 interests (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, (d) its repayment of loans from FCX, (e) its receipt of the conveyance of the overriding royalty interests from McMoRan pursuant to the master conveyance, (f) its receipt of royalties from McMoRan, and (g) its cash dividends to unitholders, if any, 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 in 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 generally has none of the rights described in the preceding sentence, and neither the Royalty Trust nor the Royalty Trust unitholders has any such rights. The Royalty Trust's 5% gross overriding royalty interest in future production from each subject interest is proportionately reduced based on McMoRan's or HOGA's respective working interest in the subject interest.

The subject interests originally consisted of 20 specified Inboard Lower Tertiary/Cretaceous prospects (with target depths generally greater than 18,000 feet total vertical depth) located in the shallow waters of the Gulf of Mexico and onshore in South Louisiana. As of December 31, 2018, only the onshore Highlander subject interest had any reserves classified as proved, probable or possible and had established commercial production. On February 5, 2019, McMoRan completed the sale of all of its rights, title and interest in and to the onshore

Highlander subject interest pursuant to a purchase and sale agreement with Highlander Oil & Gas Assets LLC (HOGA) (the Highlander Sale). The onshore Highlander subject interest was sold subject to the overriding royalty interest in future production held by the Royalty Trust. As a result of the Highlander Sale, HOGA has a 72 percent working interest and an approximate 49 percent net revenue interest in the onshore Highlander subject interest. The Royalty Trust continues to hold a 3.6 percent overriding royalty interest in the onshore Highlander subject interest. McMoRan will remain operator of the onshore Highlander subject interest during a transition period until HOGA qualifies and is designated as operator, which is expected to occur on or before May 31, 2019. McMoRan has informed the Trustee that it has no plans to pursue, has relinquished, has allowed to expire or has sold all of the subject interests.

No impairment charges were recorded during the years ended December 31, 2018, and December 31, 2017.

The onshore Highlander subject interest is the only producing subject interest and 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. An amortization charge related to production volumes associated with the onshore Highlander subject interest reduced the carrying value of the overriding royalty interests in the subject interests by $699,450 and $1,750,845 for the years ended December 31, 2018 and 2017, respectively. Accumulated amortization was $5,461,102 and $4,761,652 for the years ended December 31, 2018 and 2017, respectively.

The Royalty Trust has no ability to direct or influence the exploration or development of the subject interests. In addition, none of FCX, McMoRan or HOGA is under any obligation to fund or to commit any other resources to the exploration or development of the subject interests. Further, FCX, McMoRan and HOGA 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 earliest to occur 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 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. In addition, 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 following the end of such nine-month period. The volume-weighted average price per royalty trust unit was $0.05 for the nine-month period ended March 15, 2019.

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.

The Tax Cuts and Jobs Act (the TCJA) enacted on December 22, 2017, includes significant modifications to existing U.S. tax laws, including changes to the corporate and individual rates. Royalty Trust unitholders should consult their own tax advisors regarding the impact of the TCJA on the income, gain, loss or deduction derived by the unitholder for the Royalty Trust.

5. RELATED PARTY TRANSACTIONS

Royalties. As of December 31, 2018, only the onshore Highlander subject interest had established commercial production. In accordance with the master conveyance, the Royalty Trust received royalties from McMoRan of $1,462,796 and $1,376,758 during the years ended December 31, 2018 and 2017, respectively, resulting from production from the onshore Highlander subject interest. Royalties received by the Royalty Trust must first be used to (i) satisfy Royalty Trust administrative expenses and (ii) reduce Royalty Trust indebtedness. The Royalty Trust had no indebtedness outstanding as of December 31, 2018. Additionally, the Trustee has established a minimum cash reserve of $250,000. As a result, distributions are made to Royalty Trust unitholders only when royalties received less administrative expenses incurred and repayment of any indebtedness exceeds the $250,000 minimum cash reserve. See Note 6.

Funding of Administrative Expenses. Pursuant to the royalty trust agreement, FCX has agreed to pay annual trust expenses up to $350,000, with no right of repayment or interest due, to the extent the Royalty Trust lacks sufficient funds to pay administrative expenses. No such contributions were made during the years ended December 31, 2018, and 2017. 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. Since inception, FCX loaned $650,000 to the Royalty Trust under this arrangement, all of which had been repaid prior to December 31, 2018, including $500,000 during 2017, and no amounts were outstanding at December 31, 2018.

Pursuant to the royalty trust agreement, FCX 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 if its funds are inadequate 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 (and short-term investments) 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’s annual compensation has been $200,000 since 2016, when it increased from $150,000 as a result of the Royalty Trust’s receipt of royalties related to production from the onshore Highlander subject interest beginning in the second quarter of 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, 2018, the Royalty Trust had 230,172,696 royalty trust units outstanding and FCX, through its indirect wholly owned subsidiary McMoRan, held 62,286,299 royalty trust units (or

27.1% of the outstanding royalty trust units). In connection with the Highlander Sale on February 5, 2019, McMoRan assigned 31,143,150 royalty trust units to HOGA.

6. DISTRIBUTIONS
Distributable income totaled $838,155 and $356,486 for the years ended December 31, 2018 and 2017, respectively. A summary of quarterly per unit distributions for the years ended December 31, 2018 and 2017 is set forth in the table below.

Three-month period ended:	2018 Per Unit Amount	Record Date	Payment Date	2017 Per Unit Amount	Record Date	Payment Date
March 31	$0.001138	4/30/2018	5/14/2018	$—	—	—
June 30	$0.000558	7/30/2018	8/13/2018	$—	—	—
September 30	$0.000837	10/30/2018	11/14/2018	$0.000648	10/30/2017	11/13/2017
December 31	$0.001108	1/30/2019	2/13/2019	$0.000901	1/30/2018	2/13/2018

On January 17, 2019, the Royalty Trust declared a cash distribution of $0.001108 per unit payable on February 13, 2019, to unitholders of record on January 30, 2019. These distributions are not necessarily indicative of future distributions.

Natural gas sales volumes (in thousands of cubic feet, or Mcf), average sales price (per Mcf) and net cash proceeds available for distribution for the years ended December 31, 2018 and 2017, are set forth in the table below.

	2018	2017
Natural gas sales volumes (Mcf) [(a)]	576,119	525,972
Natural gas average sales price (per Mcf)	$2.85	$2.91
Gross proceeds	$1,643,878	$1,532,419
Post-production costs and specified taxes	$(181,082)	$(155,661)
Royalty income	$1,462,796	$1,376,758
Interest and dividend income	$5,910	$2,276
Administrative expenses	$(630,551)	$(534,085)
Income in excess of administrative expenses	$838,155	$844,949
Payment of loan payable to FCX	$—	$(500,000)
Adjustment to minimum cash reserve	$—	$11,537
Net cash proceeds available for distribution	$838,155	$356,486

(a) Attributable to the onshore Highlander subject interest, which is the only subject interest with commercial production.

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

8. SUBSEQUENT EVENTS
On February 5, 2019, McMoRan completed the sale of all of its rights, title and interest in and to the onshore Highlander subject interest pursuant to a purchase and sale agreement with HOGA (the Highlander Sale). The onshore Highlander subject interest was sold subject to the overriding royalty interest in future production held by the Royalty Trust. As a result of the Highlander Sale, HOGA has a 72 percent working interest and an approximate 49 percent net revenue interest in the onshore Highlander subject interest. The Royalty Trust continues to hold a 3.6 percent overriding royalty interest in the onshore Highlander subject interest. McMoRan will remain operator of the onshore Highlander subject interest during a transition period until HOGA qualifies and is designated as operator, which is expected to occur on or before May 31, 2019. McMoRan has informed the Trustee that it has no plans to pursue, has relinquished, has allowed to expire or has sold all of the subject interests.

On January 17, 2019, the Royalty Trust declared a cash distribution of $0.001108 per unit payable on February 13, 2019, to unitholders of record on January 30, 2019.

The Royalty Trust evaluated all other events subsequent to December 31, 2018, 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.

9. SUPPLEMENTARY OIL AND GAS INFORMATION (UNAUDITED)
Proved Natural Gas Reserve Information. The following information summarizes the net proved reserves of natural gas and the standardized measure as described below. All of the Royalty Trust's reserves are natural gas reserves and 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 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 natural gas reserve estimates are to some degree subjective, the quantities of natural gas that are ultimately recovered, production and specified post-production costs and taxes allowable under the trust agreement and future 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 and any adjustments in the projected economic life of such properties resulting from changes in product prices.

Decreases in the prices of 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 price for reserve determination is the Henry Hub spot price for natural gas. As of March 2019, the twelve-month average of the first-day-of-the-month historical reference price for natural gas has declined from $3.10 per MMBtu at December 31, 2018, to $3.07 per MMBtu.

	Natural Gas (MMcf)[a]	
	2018	2017
Proved reserves:		
Balance at beginning of year	1,528	944
Revisions of previous estimates[b]	424	1,110
Extensions and discoveries	—	—
Acquisition of reserves in-place	—	—
Sale of reserves in-place	—	—
Purchase of reserves in-place	—	—
Production	(576)	(526)
Balance at end of year	1,376	1,528
Proved developed reserves at end of year	1,376	1,528
Proved undeveloped reserves at end of year	—	—

(a) MMcf = millions of cubic feet.
(b)

For the years ended December 31, 2018 and 2017, positive revisions associated with the onshore Highlander subject interest were primarily due to positive well performance for the Highlander well.

Standardized Measure. The Standardized Measure (discounted at 10%) from production of proved natural gas reserves has been developed as of December 31, 2018 and 2017, in accordance with SEC guidelines. McMoRan estimated the quantity of proved natural gas reserves associated with the overriding royalty interests 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 Trust's proved natural 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 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, 2018 and 2017, and held constant throughout the life of the properties. Future income taxes are not presented given the Royalty Trust's status as a non-taxable "pass through" entity. See Note 4.

The average realized sales price used in the Royalty Trust's reserve report, was $2.98 per Mcf of natural gas as of December 31, 2018 and $2.84 per Mcf of natural gas as of December 31, 2017.

The Standardized Measure related to proved reserves as of December 31 is presented below:

	2018	2017
Future cash inflows	$4,099,000	$4,342,600
Future costs applicable to future cash flows:		
Production costs (primarily production and ad valorem taxes)	(567,900)	(628,800)
Development and abandonment costs	—	—
Future income taxes [a]	—	—
Future net cash flows	3,531,100	3,713,800
Discount for estimated timing of net cash flows (10% discount rate) [b]	(398,800)	(450,200)
Standardized measure	$3,132,300	$3,263,600

(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 is presented below:

	2018	2017
Balance at beginning of year	$3,263,600	$1,729,800
Changes during the year		
Sales, net of production expense	(1,462,795)	(1,376,758)
Net changes in sales and transfer prices, net of production expenses	171,511	404,388
Extensions, discoveries and improved recoveries	—	—
Changes in estimated future development costs	—	—
Previously estimated development costs incurred during the year	—	—
Sales of reserves in-place	—	—
Revisions of quantity estimates	953,406	2,511,611
Changes due to timing and other	(119,782)	(178,421)
Accretion of discount	326,360	172,980
Net change in income taxes	—	—
Total changes	(131,300)	1,533,800
Balance at end of year	$3,132,300	$3,263,600

10. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	Royalty Income	Income in Excess of Administrative Expenses (Administrative Expenses in Excess of Income)	Distributable Income [(a)]	Distributable Income Per Unit [(a)]
2018				
1st Quarter	$369,255	$ 262,027	$ 262,027	$ 0.001138
2nd Quarter	310,938	128,544	128,544	0.000558
3rd Quarter	385,988	192,565	192,565	0.000837
4th Quarter	396,615	255,019	255,019	0.001108
	$1,462,796	$ 838,155	$ 838,155	$ 0.003641
2017				
1st Quarter	$398,689	$ 274,743	$ —	$ —
2nd Quarter	307,040	174,287	—	—
3rd Quarter	355,060	188,588	149,155	0.000648
4th Quarter	315,969	207,331	207,331	0.000901
	$1,376,758	$ 844,949	$ 356,486	$ 0.001549

(a) These distributions are not necessarily indicative of future distributions.

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 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, 2018.

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) Changes in Internal Control over Financial Reporting. During the quarter ended December 31, 2018, 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, with the exception of Freeport-McMoRan Inc., which amended its original Form 3 to include an additional 861 royalty trust units that should have been reflected in the original report filed on May 29, 2014.

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 and any information that FCX has provided to the Trustee, 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, 2018, 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]
Neil S. Subin 3300 South Dixie Highway Suite 1-365 West Palm Beach, FL 33405	45,228,326	(b)	19.6%
Highlander Oil & Gas Assets LLC 9 Greenway Plaza, Suite 1400 Houston, TX 77046	31,143,150	(c)	13.5%
Freeport-McMoRan Inc. McMoRan Oil & Gas LLC 333 North Central Avenue Phoenix, AZ 85004	31,143,149	(d)	13.5%
Leon G. Cooperman 11431 W. Palmetto Park Road Boca Raton, FL 33428	21,651,695	(e)	9.4%
Akanthos Capital Management, LLC 21700 Oxnard Street, Suite 1730 Woodland Hills, CA 91367	16,135,696	(f)	7.0%

(a) Based on 230,172,696 royalty trust units outstanding as of December 31, 2018.

(b) Based on a Schedule 13G filed with the SEC on January 23, 2018, by Neil S. Subin in his individual capacity and as president and manager of MILFAM, LLC, which serves as manager, general partner, or investment advisor of a number of entities formerly managed or advised by the late Lloyd I. Miller, III. Mr. Subin has (a) sole voting and investment power over 44,965,980 of the royalty trust units reported and (b) shared voting and investment power over 262,346 of the royalty trust units reported.

(c)

Based on a Schedule 13G filed with the SEC on March 15, 2019 by HOGA and Magnolia Oil & Gas Corporation (Magnolia). HOGA is a wholly owned subsidiary of Highlander Oil & Gas Holdings LLC. MGY Louisiana LLC holds approximately 85% of the units in Highlander Oil & Gas Holdings LLC. MGY Louisiana LLC is a wholly owned subsidiary of Magnolia Oil & Gas Operating LLC, which is a wholly owned subsidiary of Magnolia Oil & Gas Intermediate LLC, which is a wholly owned subsidiary of Magnolia Oil & Gas Parent

LLC, whose managing member is Magnolia Oil & Gas Corporation ("Magnolia"). HOGA and Magnolia have shared voting and investment power over all of the royalty trust units reported. Magnolia's address is Nine Greenway Plaza, Suite 1300, Houston, TX 77046.

(d) Based on Form 4 filed with the SEC on February 7, 2019, by FCX.

(e) Based on an amended Schedule 13G filed with the SEC on November 13, 2015, by Leon G. Cooperman, on his own behalf and on behalf of affiliated investment firms and managed accounts identified therein. Mr. Cooperman represents that he has sole voting and investment power over 5,000,000 royalty trust units. Mr. Cooperman subsequently filed an amended Form 4 on December 4, 2015, reporting an additional 16,651,695 royalty trust units held in managed accounts and private investment entities over which he has investment discretion but disclaims beneficial ownership except to the extent of his pecuniary interest therein.

(f) Based on a Schedule 13G filed with the SEC on February 14, 2018, by Akanthos Capital Management, LLC. According to the filing, the reporting person has sole voting and investment power with respect to 16,135,696 royalty trust units and no shared voting or investment power with respect to royalty trust units; all securities reported are owned by the reporting person's advisory clients, none of which to the reporting person's knowledge owns more than 5% of the total outstanding royalty trust units.

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, (d) its repayment of loans from FCX, (e) its receipt of the conveyance of the overriding royalty interests from McMoRan pursuant to the master conveyance, (f) its receipt of royalties from McMoRan, and (g) its cash distributions to unitholders, if any, the Royalty Trust has not conducted any activities.

Funding of Administrative Expenses. Pursuant to the royalty trust agreement, FCX has agreed to pay annual trust expenses up to $350,000, with no right of repayment or interest due, to the extent the Royalty Trust lacks sufficient funds to pay administrative expenses. No such contributions were made during the years ended December 31, 2018 and 2017. 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. Since inception, FCX has loaned $650,000 to the Royalty Trust under this arrangement, all of which had been repaid prior to December 31, 2018, including $500,000 during 2017, and no amounts were outstanding at December 31, 2018.

Pursuant to the royalty trust agreement, FCX 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 if its funds are inadequate 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 (and short-term investments) 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’s annual compensation has been $200,000 since 2016, when it increased from $150,000 as a result of the Royalty Trust’s receipt of royalties related to production from the onshore Highlander subject interest beginning in the second quarter of 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.

Royalty Trust Units Held by FCX. At December 31, 2018, the Royalty Trust had 230,172,696 royalty trust units outstanding and FCX, through its indirect wholly owned subsidiary McMoRan, held 62,286,299 royalty trust units (or 27.1% of the outstanding royalty trust units). In connection with the Highlander Sale on February 5, 2019, McMoRan assigned 31,143,150 royalty trust units to HOGA.

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:

	2018	2017
Audit Fees	$170,000	$170,000
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.

Exhibit Number	Exhibit Title	Filed or Furnished 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	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
10.2	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
23	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	Report of Netherland, Sewell & Associates, Inc.	X			

Item 16. Form 10-K Summary

Not applicable.

GLOSSARY

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

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

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 environmental pre-leasing 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).

British thermal unit or Btu. The amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Gross acre. An acre in which McMoRan 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 acre. Deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in 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.

Proved reserves. Those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible.

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.

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 21, 2019

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
February 14, 2019

The Bank of New York Mellon Trust Company, N.A.
as Trustee
Gulf Coast Ultra Deep Royalty Trust
601 Travis Street, 16th Floor
Houston, Texas 77002

Ladies and Gentlemen:

In accordance with your request, we have estimated the proved developed producing reserves and future revenue, as of December 31, 2018, to the Gulf Coast Ultra Deep Royalty Trust (Gulf Coast) overriding royalty interest in the Jeanerette Minerals 1 well 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 this report constitute all of the 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 gross (100 percent) gas reserves and the net gas reserves and future net revenue to the Gulf Coast interest in the Jeanerette Minerals 1 well, as of December 31, 2018, to be:

	Gas Reserves (MMCF)		Future Net Revenue (M$)	
Category	Gross (100)%	Net	Total	Present Worth at 10%
Proved Developed Producing	44,143.5	1,376.1	3,531.1	3,132.3

Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases. This property has never produced commercial volumes of condensate.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. Our study indicates that as of December 31, 2018, there are no proved developed non-producing or proved undeveloped reserves for this property. As requested, probable and possible reserves that exist for this property have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage.

Gross revenue is Gulf Coast's share of the gross (100 percent) revenue from the property prior to any deductions. Future net revenue is after deductions for Gulf Coast's share of production taxes, ad valorem taxes, and post-production operating expenses but before consideration of any income 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 property.

The gas price used in this report is based on the 12-month unweighted arithmetic average of the first-day-of-the-month Henry Hub spot price for each month in the period January through December 2018. The average price of $3.100 per MMBTU is adjusted for energy content, transportation fees, and market differentials. The adjusted gas price of $2.979 per MCF is held constant throughout the life of the property.

Because this report is for the Gulf Coast overriding royalty interest in this property, no operating costs would be incurred, except for the post-production operating costs of $205,550 per month and $0.03 per MCF of gas. Operating costs have been used to confirm economic producibility and determine economic limits for the property. Operating costs are based on operating expense records of Freeport McMoRan Oil & Gas LLC (FM O&G), the operator of the property, and include only direct lease- and field-level costs. Operating 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 property, nor did we examine the mechanical operation or condition of the well and facilities. Since Gulf Coast owns an overriding royalty interest rather than a working interest in this property, it would not incur any costs due to possible environmental liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Gulf Coast interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Gulf Coast receiving its overriding royalty interest share of estimated future gross production. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical field- and lease-level accounting statements.

The reserves shown 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 property will be developed consistent with current development plans as provided to us by FM O&G, that the property 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 and the costs related thereto 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 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, historical price and cost information, 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 performance analysis, 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. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the property 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.

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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 this property 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: February 14, 2019	Date Signed: February 14, 2019

JRC:RS

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.

A-3

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 2018 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 2018 Petroleum Resources Management System:

Developed Producing Reserves - Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves - Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that 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 that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(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.

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

(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.

(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

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(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.
(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.

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(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.
(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

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(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% 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.

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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.

(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.

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