UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

☒ **Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the quarterly period ended March 31, 2015**

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: 0-06910

TEL OFFSHORE TRUST

(Exact name of registrant as specified in its charter)

Texas (State or other jurisdiction of incorporation or organization)	**76-6004064** (I.R.S. Employer Identification No.)
The Bank of New York Mellon Trust Company, N.A. **919 Congress Avenue** **Austin, Texas** (Address of principal executive offices)	**78701** (Zip Code)

(512) 236-6599

(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

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

Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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

As of May 13, 2015, 4,751,510 Units of Beneficial Interest in TEL Offshore Trust were outstanding.

NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q (this "Form 10-Q") includes "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. All statements other than statements of historical facts included in this Form 10-Q, including without limitation, statements under "Trustee's Discussion and Analysis of Financial Condition and Results of Operations" in Item 2 of Part I and elsewhere herein regarding the financial position, production and reserve growth, and other plans and objectives are forward-looking statements. Forward-looking statements are generally accompanied by words such as "estimate," "project," "predict," "believe," "expect," "anticipate," "could," "may," "should," "intend" or other words that convey the uncertainty of future events or outcomes. These forward-looking statements are based on current expectations and assumptions about future events. Although Chevron USA, Inc., the Managing General Partner of the TEL Offshore Trust Partnership, has advised the Trust that the Managing General Partner believes that the expectations reflected in the forward-looking statements contained herein are reasonable, no assurance can be given that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from expectations are disclosed in the risk factors discussed in Item 1A of Part I of the Trust's Annual Report on Form 10-K for the year ended December 31, 2014 (the "2014 10-K") and such other factors as may be set forth from time to time in the Trust's filings with the Securities and Exchange Commission. All subsequent written and oral forward-looking statements attributable to the Managing General Partner or the Trust or persons acting on behalf of the Managing General Partner or the Trust are expressly qualified in their entirety by such factors. The Trust assumes no obligation, and disclaims any duty, to update these forward-looking statements.

PART I—FINANCIAL INFORMATION

Item 1. Condensed Financial Statements.

TEL OFFSHORE TRUST
CONDENSED STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS (UNAUDITED)

	March 31, 2015	December 31, 2014
Assets		
Cash and cash equivalents	$171,638	$243,923
Net overriding royalty interest in oil and gas properties, net of accumulated amortization of $28,267,655 and $28,255,605, respectively	11,363	12,050
Total assets	$183,001	$255,973
Liabilities and Trust Corpus		
Distribution payable to Unit holders	$—	$—
Cash advances	138,593	116,277
Note payable	363,000	363,000
Reserve for future Trust expenses	—	—
Trust corpus (4,751,510 Units of beneficial interest authorized and outstanding)	(318,592)	(223,304)
Total liabilities and Trust corpus	$183,001	$255,973

CONDENSED STATEMENTS OF DISTRIBUTABLE INCOME (UNAUDITED)

	Three Months Ended March 31,	
	2015	2014
Royalty income	$—	$—
Interest income	—	—
	—	—
Decrease in reserve for future Trust expenses	—	488,925
Proceeds from Note and cash advances used for Trust expenses	94,604	—
General and administrative expenses	(94,604)	(488,925)
Distributable income	—	—
Distributable income per Unit (basic and diluted (4,751,510 Units))	$.000000	$.000000
Distributions per Unit (4,751,510 Units)	$.000000	$.000000

CONDENSED STATEMENTS OF CHANGES IN TRUST CORPUS (UNAUDITED)

	Three Months Ended March 31,	
	2015	2014
Trust corpus, beginning of period	$(223,304)	$14,515
Distributable income	—	—
Distribution payable to Unit holders	—	—
Proceeds from Note and cash advances used for Trust expenses	(94,601)	—
Amortization of net overriding royalty interest	(687)	(387)
Trust corpus, end of period	$(318,592)	$14,128

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

TEL OFFSHORE TRUST

NOTES TO CONDENSED FINANCIAL STATEMENTS (UNAUDITED)

(1) Trust Organization

Tenneco Offshore Company, Inc. (“Tenneco Offshore”) created the TEL Offshore Trust (“Trust”) effective January 1, 1983, pursuant to the Plan of Dissolution (“Plan”) approved by Tenneco Offshore’s stockholders on December 22, 1982. In accordance with the Plan, the TEL Offshore Trust Partnership (“Partnership”) was formed in which the Trust owns a 99.99% interest and Tenneco Oil Company initially owned a .01% interest. In general, the Plan was effected by transferring an overriding royalty interest equivalent to a 25% net profits interest (the “Original Royalty”) in the oil and gas properties (the “Royalty Properties”) of Tenneco Exploration, Ltd. located offshore Louisiana to the Partnership and issuing certificates evidencing units of beneficial interest in the Trust (“Units”) in liquidation and cancellation of Tenneco Offshore’s common stock. The term “Original Royalty” shall refer to the initial 25% net profits interest in the Royalty Properties and the term “Royalty” shall refer to the applicable net profits interest held from time to time by the Partnership following the Royalty Sales (as defined in Note 3 below).

On January 14, 1983, Tenneco Offshore distributed Units to holders of Tenneco Offshore’s common stock on the basis of one Unit for each common share owned on such date.

The terms of the Trust Agreement, dated January 1, 1983 (as amended, the “Trust Agreement”), provide, among other things, that:

(a) the Trust is a passive entity and cannot engage in any business or investment activity or purchase any assets;

(b) the interest in the Partnership can be sold in part or in total for cash upon approval of a majority of the Unit holders;

(c) the Trustees, as defined below, can establish cash reserves and borrow funds to pay liabilities of the Trust and can pledge the assets of the Trust to secure payments of the borrowings. At March 31, 2015 and December 31, 2014 the reserve amount was $0;

(d) the Trustees will make cash distributions to the Unit holders in January, April, July and October of each year as discussed in Note 4; and

(e) the Trust will terminate upon the first to occur of the following events: (i) total future net revenues attributable to the Partnership’s interest in the Royalty, as determined by independent petroleum engineers, as of the end of any year, are less than $1.2 million (assuming no further sales of any interests in the Royalty) or (ii) a decision to terminate the Trust by the affirmative vote of Unit holders representing a majority of the Units. Future net revenues attributable to the Royalty were estimated at approximately $7.3 million (unaudited) as of October 31, 2014. Such future net revenues include projected reserves attributable to the four wells drilled by Arena Offshore, LP (“Arena”) but do not include capital expenditures attributable to the redevelopment of to Eugene Island 339. Upon termination of the Trust, the Corporate Trustee (as defined below) will sell for cash all assets held in the Trust estate and make a final distribution to the Unit holders of any funds remaining, after all Trust liabilities have been satisfied.

On October 27, 2011, the Partnership sold 20% of the Original Royalty (or 5% of 8/8ths) for gross proceeds of $1,600,000. See Note 3.

On October 31, 2013, the Partnership consummated the sale of 25% of its remaining interest in the Original Royalty (or 5% of 8/8ths) and following such sale now holds 60% of the Original Royalty interest (or 15% of 8/8ths). See Note 3.

The Trust is currently administered by The Bank of New York Mellon Trust Company, N.A. (the “Corporate Trustee”), which succeeded JPMorgan Chase Bank, N.A. as the corporate trustee, effective October 2, 2006 pursuant to an agreement under which The Bank of New York acquired substantially all of the corporate trust business of JPMorgan Chase (formerly known as The Chase Manhattan Bank), and Gary C. Evans, Thomas H. Owen, Jr., and Jeffrey S. Swanson (the “Individual Trustees”), as trustees (collectively, the “Trustees”).

The Trustees, including the Corporate Trustee, have no authority over, have not evaluated and make no statement concerning, the internal control over financial reporting of any of the owner or owners of the Royalty Properties (the "Working Interest Owners").

(2) Basis of Accounting and Going Concern

The accompanying unaudited financial information has been prepared by the Corporate Trustee. The accompanying financial information is prepared on a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America ("GAAP"). The Trustees believe that the information furnished reflects all adjustments that are, in the opinion of the Trustees, necessary for a fair presentation of the results for the interim periods presented. Such adjustments are of a normal and recurring nature. The financial information should be read in conjunction with the financial statements and notes thereto included in the Trust's Annual Report on Form 10-K for the year ended December 31, 2014.

Overriding Royalty Interest. The Trust uses the modified cash basis of accounting to report Trust receipts from the overriding royalty and payments of expenses incurred. The actual cash distributions to the Trust are made based on the terms of the conveyance that created the Trust's overriding royalty interest. The overriding royalty interest entitles the Trust to receive revenues (oil, gas and natural gas liquid sales) less expenses (the amount by which all royalties, lease operating expenses including well workover costs, production and property taxes, post-production costs including plugging and abandonment, and producing overhead of the underlying properties) multiplied by the Partnership's interest in the Original Royalty. The Original Royalty initially represented a 25% net profits interest but after the Royalty Sales, the Royalty now represents a 15% net profits interest. Actual cash receipts may vary due to timing delays of cash receipts from the property operators or purchasers and due to wellhead and pipeline volume balancing agreements or practices.

Modified Cash Basis of Accounting. The condensed financial statements of the Trust, as prepared on a modified cash basis, reflect the Trust's assets, liabilities, Trust corpus, earnings and distributions, as follows:

(a) Royalty income from the overriding royalty interest is recorded when received, including the effect of overtaken or undertaken positions and negative or positive adjustments, by the Corporate Trustee on the last business day of each calendar quarter. In addition, Royalty income includes amounts related to funds deposited or released from the Special Cost Escrow account—see (d);

(b) Trust general and administrative expenses (which include the Trustee's fees as well as accounting, engineering, legal, and other professional fees) are recorded when paid by the Trust rather than when incurred;

(c) Cash reserves for Trust expenses may be established by the Trustee for certain expenditures that would not be recorded as contingent liabilities under GAAP;

(d) The funds deposited or released from the Special Cost Escrow account are recorded at the time of payment or receipt. The Special Cost Escrow account is an account of the Working Interest Owners and is not reflected in the condensed financial statements of the Trust;

(e) Amortization of the investment in overriding royalty interest is calculated based on the units-of-production method. Such amortization is charged directly to Trust corpus and does not affect distributable income; and

(f) Proceeds from loans used to pay for Trust expenses is charged directly to Trust corpus.

This manner of reporting income and expenses is considered to be the most meaningful because the quarterly distributions to Unit holders are based on net cash receipts received from the Working Interest Owners. The condensed financial statements of the Trust differ from condensed financial statements prepared in accordance with GAAP, because, under such principles, Royalty income and Trust general and administrative expenses for a quarter would be recognized on an accrual basis. In addition, amortization of the net overriding royalty interest, calculated on a units-of-production basis, is charged directly to Trust corpus since such amount does not affect distributable income. This comprehensive basis of accounting other than GAAP corresponds to the accounting permitted for royalty trusts by the U.S. Securities and Exchange Commission, as specified by Staff Accounting Bulletin Topic 12:E, *Financial Statements of Royalty Trusts.*

Oil and Gas Reserves. The proved oil and gas reserves for the underlying properties are estimated by independent petroleum engineers. Reserve engineering is a subjective process that is dependent upon the quality of available data and the interpretation thereof. Estimates by different engineers often vary, sometimes significantly. In addition, physical factors such as the results of drilling, testing and production subsequent to the date of an estimate, as well as economic factors such as changes in product prices and production costs, may justify revision of such estimates. Accordingly, oil and gas quantities ultimately recovered and the timing of production may be substantially different from estimates.

The standardized measure of discounted future net cash flows is prepared using assumptions made pursuant to FASB and SEC guidelines. Such assumptions include using average fiscal-year oil and gas prices (calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month reporting period) and year-end costs for estimated future production expenditures. Discounted future net cash flows are calculated using a 10% discount rate. Changes in any of these assumptions could have a significant impact on the standardized measure. The standardized measure does not necessarily result in an estimate of the current fair market value of proved reserves.

Amortization of Overriding Royalty Interest. The Trust amortizes the investment in overriding royalty interest using the units-of-production method. The Trust's rate of recording amortization is dependent upon the estimates of total proved reserves, which incorporates various assumptions and future projections. If the estimates of total proved reserves decline significantly, the rate at which the Trust records amortization expense would increase, reducing Trust corpus. Such a decline in reserves may result from lower commodity prices, which may make it uneconomic to produce from higher cost fields. The Trust is unable to predict changes in reserve quantity estimates as such quantities are dependent on future economic and operational conditions.

Impairment of Investment in Overriding Royalty Interest. The Trust reviews overriding royalty interests in oil and gas properties for possible impairment whenever events or circumstances indicate the carrying amount of the asset may not be recoverable. If there is an indication of impairment, the Trust prepares an estimate of future cash flows (undiscounted and without interest charges) expected to result from the use of the asset and its eventual disposition. If these cash flows are less than the carrying amount of the asset, an impairment loss is recognized to write down the asset to its estimated fair value. Preparation of estimated expected future cash flows is inherently subjective and is based on the Corporate Trustee's best estimate of assumptions concerning expected future conditions. There were no write downs taken in the three months ended March 31, 2015.

Cash and Cash Equivalents. Cash and cash equivalents include all highly liquid short-term investments with original maturities of three months or less.

Reserve for future Trust expenses. Represents cash reserves for future Trust expenses established by the Trustee. The changes in reserves for future Trust expenses includes both changes of amounts deemed necessary by the Trustees and related distributions, as well as amounts paid from the reserve during periods when the Trust has insufficient income to pay Trust expenses. See Note 6.

Proceeds from Sale of Overriding Royalty. The Trust records proceeds from the sale of overriding royalty interests when received.

Special Cost Escrow account. The Special Cost Escrow account (see Note 5) is established for future costs to be incurred to plug and abandon wells, dismantle and remove platforms, pipelines and other production facilities, and for the estimated amount of future capital expenditures on the Royalty Properties. The funds held in the Special Cost Escrow account are not reflected in the condensed financial statements of the Trust. However, funds deposited to or released from the Special Cost Escrow account are included in Royalty income.

Use of Estimates. The preparation of financial statements requires the Trustees to make use of estimates and assumptions that affect amounts reported in the condensed financial statements as well as certain disclosures. Actual results could differ from those estimates.

Recent Accounting Pronouncements. There were no accounting pronouncements issued during the three months ended March 31, 2015, applicable to the Trust or its condensed financial statements.

Going Concern. The accompanying condensed financial statements have been prepared assuming that the Trust will continue as a going concern. Financial statements prepared on the going concern basis assume the realization of assets and the settlement of liabilities in the normal course of business. The Trust has not received Royalty income since the fourth quarter of 2008. The lack of sufficient Net Proceeds to make distributions in the foreseeable future as discussed in Note 4 and the inability to maintain adequate cash reserves raise substantial doubt about the Trust's ability to continue as a going concern. Certain potential alternatives available to the Trustees are described in Note 6. The condensed financial statements do not include any adjustments that might result from the outcome of this uncertainty.

(3) Net Overriding Royalty Interest

The Original Royalty entitled the Trust to its share (99.99%) of 25% of the Net Proceeds attributable to the Royalty Properties. The Conveyance, dated January 1, 1983, provides that the Working Interest Owners will calculate, for each period of three months commencing the first day of February, May, August and November, an amount equal to 25% of the Net Proceeds from their oil and gas properties for the period. Generally, "Net Proceeds" means the amount received by the Working Interest Owners from the sale of minerals from the Royalty Properties less operating and capital costs incurred, management fees and expense reimbursements owing to the Managing General Partner of the Partnership, applicable taxes other than income taxes, and the Special Cost Escrow account. The Special Cost Escrow account is established for the future costs to be incurred to plug and abandon wells, dismantle and remove platforms, pipelines and other production facilities, and for the estimated amount of future capital expenditures on the Royalty Properties. Net Proceeds do not include amounts received by the Working Interest Owners as advance gas payments, "take-or-pay" payments or similar payments unless and until such payments are extinguished or repaid through the future delivery of gas.

On October 27, 2011, the Trust issued a press release announcing that the Partnership had consummated the sale (the "2011 Royalty Sale") of 20% of the Original Royalty (or 5% of 8/8ths). The 2011 Royalty Sale was made to RNR Production, Land and Cattle Company, Inc. ("RNR Production") on October 27, 2011, though the assignment was effective as of August 1, 2011. Refer to Note 6 for further discussion of the 2011 Royalty Sale.

On October 31, 2013, the Trust issued a press release announcing that the Partnership had consummated the sale (the "2013 Royalty Sale" and, together with the 2011 Royalty Sale, the "Royalty Sales") of 25% of its remaining interest in the Original Royalty (or 5% of 8/8ths). The 2013 Royalty Sale to RNR Production closed on October 31, 2013, though the assignment was effective as of August 1, 2013. Refer to Note 6 for further discussion of the 2013 Royalty Sale.

Following the Royalty Sales, the Partnership has retained a 60% interest in the Original Royalty, and thus the Partnership will receive in the future only 15% of the Net Proceeds when there are sufficient Net Proceeds for distribution on the Partnership's Royalty.

On the last business day of each calendar quarter prior to August 1, 2011, the Working Interest Owners were to pay to the Partnership 25% of the Net Proceeds for the immediately preceding Quarterly Period; however, (i) as a result of the 2011 Royalty Sale, on the last business day of each calendar quarter after August 1, 2011 and prior to August 1, 2013, the Working Interest Owners were to pay to the Partnership 20% of the Net Proceeds for the immediately preceding Quarterly Period and (ii) as a result of the 2013 Royalty Sale, on the last business day of each calendar quarter after August 1, 2013, the Working Interest Owners are to pay to the Partnership 15% of the Net Proceeds for the immediately preceding Quarterly Period. A Quarterly Period is each period of three months commencing on the first day of February, May, August and November. In turn, the Partnership distributes funds to its partners on the last business day of each calendar quarter. Cash distributions from the Trust, if any, are made in January, April, July and October of each year, and are payable to Unit holders of record as of the last business day of each calendar quarter. Thus, any cash conveyed to the Trust from the Partnership during the quarter ended March 31, 2015 would substantially represent the revenues and expenses from the Royalty Properties from November 2014 through January 2015. Similarly, any cash conveyed to the Trust from the Partnership during the quarter ended March 31, 2014 would substantially represent the revenues and expenses from the Royalty Properties from November 2013 through January 2014. However, there was no cash conveyed to the Trust from the Partnership pursuant to its overriding royalty interest in the Royalty Properties from either November 2014 through January 2015 or November 2013 through January 2014. The financial and operating information included in this Form 10-Q for the three months ended March 31, 2015 and March 31, 2014 represents financial and operating information with respect to the Royalty Properties for the immediately preceding months of November, December, and January. Income received pursuant to the Partnership's overriding royalty interest is recorded by the Trust on a cash basis, when it is received by the Trust from the Partnership.

(4) Distributions to Unit Holders

In accordance with the provisions of the Trust Agreement, generally all Net Proceeds received by the Trust, net of Trust general and administrative expenses and any cash reserves established for the payment of contingent or future obligations of the Trust, are distributed currently to the Unit holders. These distributions are referred to as “distributable income.” The amounts distributed are determined on a quarterly basis and are payable to Unit holders of record as of the last business day of each calendar quarter. However, cash distributions are made in January, April, July and October and include interest earned from the quarterly record date to the date of distribution.

Production ceased at Eugene Island 339 and Ship Shoal 182 and 183 following damages inflicted by Hurricane Ike in September 2008. Future Net Proceeds may take into account the Trust’s share of project costs and other related expenditures that are not covered by insurance of the operator of the Royalty Properties. On December 19, 2008, the Trust announced its fourth quarter distribution of approximately $0.7 million, which was paid on January 9, 2009. The funds available for the fourth quarter distribution were severely negatively impacted by Hurricane Ike. On March 25, 2009, the Trust announced that there would be no trust distribution for the first quarter of 2009, and the Trust has not made a distribution since January 9, 2009.

While oil and gas production at Ship Shoal 182 and 183 and at Eugene Island 339 has been partially restored, there are not likely to be sufficient Net Proceeds from the Royalty Properties for the Trust to make a regularly scheduled quarterly distribution to Unit holders for the foreseeable future. As a result of the damage inflicted by Hurricane Ike, Net Proceeds will continue to be severely impacted by reduced production. There can be no assurance by Chevron or anyone else as to the actual timing for any future distributions to the Partnership from the Royalty, and there is no guarantee that any further distributions will be made. Chevron has completed the work associated with the wells on Eugene Island 339 and informed the Trust that the aggregate cost to the Original Royalty to plug and abandon the wells, remove and abandon platforms and infrastructure and remediate the surface subject to the overriding royalty interest on Eugene Island 339 was approximately $19.8 million and that no further expenses of this nature relating to prior hurricane damage are expected to be incurred. If development and production costs of the Royalty Properties exceed the proceeds of production from the Royalty Properties, the Trust will not receive Net Proceeds until future proceeds from production exceed the total of the excess costs plus accrued interest. As a result of the damage inflicted by Hurricane Ike, the Trust has not received Net Proceeds since December 2008. As of January 31, 2015, aggregate development and production costs for the Royalty Properties since November 2008 have exceeded the related proceeds of production from the Royalty Properties by approximately $2.3 million, net to the entire Original Royalty ($1.4 million applicable to the Trust).

For the three months ended March 31, 2015, the Trust had undistributed net income of $292,096, representing the Trust’s portion of the aggregate undistributed net income of $1,947,304 associated with the Royalty Properties for the three months ended March 31, 2015. Undistributed net income represents positive Net Proceeds generated during the respective period, but not distributed by the Working Interest Owners.

The Trust’s portion of the cumulative undistributed net loss associated with the Royalty Properties was $1.4 million as of January 31, 2015. Undistributed net loss represents the amount of development and production costs associated with the Royalty that exceed the proceeds of production from the Royalty Properties during the period. An undistributed net loss is carried forward and offset, in future periods, by positive proceeds earned by the related Working Interests Owner(s). The Trust will not receive Net Proceeds until (i) future proceeds from production exceed the total of the excess costs plus applicable accrued interest and (ii) any additional indebtedness of the Trust, such as the 2014 Note (as defined in Note 10 below) and other cash advances made by The Bank of New York Mellon, are repaid in full. In addition, to the extent Net Proceeds are otherwise distributable to the Trust, the amount of such distribution will be significantly reduced by deposits to the Special Cost Escrow account until such Special Cost Escrow account is replenished with funds in an amount determined by the Working Interest Owners.

(5) Special Cost Escrow Account

The Special Cost Escrow is an account of the Working Interest Owners, and it is described herein for informational purposes only. The Conveyance provides for reserving funds for estimated future “Special Costs” of plugging and abandoning wells, dismantling platforms and other costs of abandoning the Royalty Properties, as well as for the estimated amount of future drilling projects and other capital expenditures on the Royalty Properties. As provided in the Conveyance, the amount of funds to be reserved is determined based on certain factors, including estimates of aggregate future production costs, aggregate future Special Costs, aggregate future net revenues and actual current net proceeds. Deposits into this account reduce current distributions and are placed in an escrow account and invested in short-term certificates of deposit. Such account is herein referred to as the “Special Cost Escrow” account. As of March 31, 2015, approximately $1,000 remained in the Special Cost Escrow account. The funds held in the Special Cost Escrow account are not reflected in the condensed financial statements of the Trust. Special Cost Escrow account funds will generally be utilized to pay Special Costs to the extent there are not adequate current net proceeds to pay such costs. Special Costs that have been paid are no longer included in the Special Cost Escrow calculation. Deposits to the Special Cost Escrow account will generally be made when the balance in the Special Cost Escrow account is less than 125% of estimated future Special Costs and there is a Net Revenues Shortfall (a calculation of the excess of estimated future costs over estimated future net revenues pursuant to a formula contained in the Conveyance). When there is not a Net Revenues Shortfall, amounts in the Special Cost Escrow account will generally be released, to the extent that Special Costs have been incurred. Amounts in the Special Cost Escrow account will also be released when the balance in such account exceeds 125% of future Special Costs.

During the three months ended March 31, 2015 and during the year ended December 31, 2014, there were no funds released from or deposited into the Special Cost Escrow account.

RNR Production was the purchaser of the partial interests in the overriding royalty interest sold pursuant to the Royalty Sales and now holds 40% of the Original Royalty (or 10% of 8/8ths) and 40% of the Partnership’s rights and obligations with respect to the Special Cost Escrow, which were assigned in connection with the Royalty Sales.

Deposits to the Special Cost Escrow Account will be required in future periods in connection with other production costs, other abandonment costs, other capital expenditures and changes in the estimates and factors described above. Such deposits are expected to result in a significant reduction in Royalty income in the periods in which such deposits are made.

(6) Reserve For Future Trust Expenses

Historically, the Trust generally maintained a cash reserve, equal to approximately three times the average annual expenses of the Trust during each of the then past three years, to provide for future administrative expenses in connection with the winding up of the Trust. However, as a result of the damage inflicted upon certain of the Royalty Properties by Hurricane Ike in September 2008, the Trust has not received sufficient Net Proceeds to maintain the reserve at such level. As of March 31, 2015 and December 31, 2014 the reserve amount was $0.

There are not likely to be positive Net Proceeds from the Royalty Properties for the foreseeable future. There can be no assurance by Chevron or anyone else as to the actual timing for any future distributions to the Partnership from the Royalty, and there is no guarantee that any further distributions will be made. The Trust has not received a distribution of Net Proceeds since December 2008. Because of the lack of Net Proceeds, the Trust has in the past not had sufficient cash flow to pay expenses on a current basis and as described below, the Trust has been required to borrow funds and to cause the Partnership to sell part of the Original Royalty in order to pay Trust expenses. As of March 31, 2015, including the proceeds from the 2014 Note (as defined below) and additional cash advances from The Bank of New York Mellon, an affiliate of the Corporate Trustee (as further described in Note 10 below), the Trust’s available cash was approximately $171,638. Based upon currently estimated expenditures, inclusive of the costs and expenses relating to the Probate Proceeding (as defined below), it is anticipated that the Trust’s existing cash reserves will be depleted during the second quarter of 2015. Following the depletion of the Trust’s existing cash reserves, it is anticipated that the Trust will continue to fund the costs and expenses of the Probate Proceeding with loans and cash advances from The Bank of New York Mellon. However, The Bank of New York Mellon will continue to evaluate the Probate Proceeding and the costs and expenses associated therewith. It is further anticipated that any such loans and cash advances will be repaid from any proceeds received by the Trust, including any proceeds received upon any sale of the remaining Royalty and will therefore reduce the cash available for distribution to the Unit holders.

Pursuant to the terms of the Trust Agreement, the Trustees are authorized to borrow funds, and pledge the assets of the Trust to secure payments of such borrowings, in the event that cash on hand is not sufficient to pay the liabilities of the Trust. In the event that the Trustees borrow funds to pay the liabilities of the Trust, no distributions will be made to the Unit holders until the indebtedness created by such borrowings has been paid in full. As discussed in Note 10, the Trustees have borrowed, and may in the future borrow, funds of which a portion were, or may be, used to pay for Trust expenses.

The Trust Agreement further provides that, if necessary to provide for the payment of specific liabilities of the Trust then due, the Trustees may without a vote of the Unit holders (a) sell all or a portion of the Trust's interest in the Partnership or any other assets of the Trust for such cash consideration as the Trustees shall deem appropriate, (b) exercise their rights under the Partnership Agreement to dissolve the Partnership, or (c) cause a sale by the Partnership of the overriding royalty interest owned by the Partnership.

On October 27, 2011, the Trust issued a press release announcing that the Partnership had consummated the 2011 Royalty Sale, which generated $1,600,000 in gross proceeds and occurred as part of a formal auction process for the Partnership's overriding royalty interest in the Royalty Properties. The Trust received from the Partnership a distribution of approximately $1,485,851, representing 99.99% of the net proceeds from the sale of $1,486,000. The Trust used such net proceeds solely for the payment of expenses of the Trust.

On October 31, 2013, the Trust issued a press release announcing that the Partnership had consummated the 2013 Royalty Sale, which generated $1,200,000 in gross proceeds and occurred as part of a formal auction process for the Partnership's remaining overriding royalty interest in the Royalty Properties. The Trust received from the Partnership a distribution of approximately $1,151,885, representing 99.99% of the net proceeds from the sale of $1,152,000. The Trust used a portion of the net proceeds received in October 2013 to repay the Trust's indebtedness a previous note payable to The Bank of New York Mellon and used the remaining net proceeds solely for the payment of expenses of the Trust.

In September 2012, the Trustees unanimously determined to suspend future payments of fees to the Trustees effective as of the third quarter of 2012, until a date to be determined in the future by the Trustees. As of December 31, 2013, the amount of such fees was approximately $339,414. The suspended fees were paid in full by the Trust in January 2014 and are included within general and administrative expenses for the three months ended March 31, 2014.

In March 2014, the Trustees again unanimously determined to suspend future payments of fees to the Trustees effective as of January 1, 2014, until a date to be determined in the future by the Trustees. As of March 31, 2015, the amount of such fees was approximately $301,814 in the aggregate. Such suspended fees will be recorded as an expense of the Trust when invoiced by the Trustees and paid.

On July 10, 2014, the Trustees filed a Petition for Modification and Termination of the Trust (the "Petition") with the Probate Court of Travis County, Texas (the "Court"). The Petition requests the Court to modify the Trust Agreement to (1) allow for the termination of the Trust by a court order, and (2) allow the Trustees, as necessary to fulfill the purposes of the Trust and without Unit holder approval to (a) sell all or any portion of the Trust's interests in the Partnership or any other assets of the Trust, (b) exercise their rights to dissolve the Partnership, or (c) cause the Partnership to sell the Royalty. The goals in filing such probate proceeding (the "Probate Proceeding") are to permit the Trustees to direct the Partnership to sell the Royalty; to distribute the net proceeds resulting from such sale, after payment of the Trust's liabilities, to the Unit holders; and, to, thereafter terminate the Partnership and the Trust. The Trustees are currently in the process of giving notice to all Unit holders, which is expected to be completed during the second quarter of 2015. Thereafter, the Trustees will seek the appointment of an ad litem for all Unit holders who have not been personally served. There can be no assurances whether the Court will grant the requested relief and, if such relief is granted, when such actions will be completed.

(7) Federal Income Tax Matters

The IRS has ruled that the Trust is a grantor trust and that the Partnership is a partnership for federal income tax purposes. Thus, the Trust will incur no federal income tax liability and each Unit holder will be treated as owning an interest in the Partnership.

(8) Commitments and Contingencies

The Managing General Partner of the Partnership has advised the Trust that, although Chevron believes that it is in general compliance with applicable health, safety and environmental laws and regulations that have taken effect at the federal, state and local levels, costs may be incurred to comply with current and proposed environmental legislation that could result in increased operating expenses on the Royalty Properties.

(9) Related Party Transactions

Each of the Working Interest Owners owns interests, for its own account, in leases that are in the same area as leases in which the Partnership has acquired or may acquire an interest. Such relationships may give rise to potential conflicts of interests in, among other things, the operation of such leases and in the acquisition and operation of any drainage leases acquired by a Working Interest Owner for its own account. Additionally, the Working Interest Owners and their affiliates are not prohibited from purchasing oil and gas produced from or attributable to any leases in which the Partnership has an interest.

Crude oil sales from Chevron Corporation accounted for approximately 100% of crude oil revenues from the Royalty Properties for the three months ended March 31, 2015 and 2014. Sales to Chevron Corporation accounted for 100% of total gas revenues from the Royalty Properties during the three months ended March 31, 2015 and 2014.

The Trust's share of Royalty income was reduced by approximately $17,396 and $18,960 for each of the three months ended March 31, 2015 and March 31, 2014, respectively, for management fees paid to the Working Interest Owners as reimbursement for expenses incurred by them on behalf of the Trust. Such management fees were calculated as 3% of the Trust's share of the sum of revenues, production expenses and capital expenditures attributable to the Royalty Properties in each of the periods above.

(10) Note Payable

On October 1, 2014, The Bank of New York Mellon made an advance to the Trust in the amount of $363,000, and The Bank of New York Mellon Trust Company, N.A., in its capacity as corporate trustee for the Trust, as the borrower, has entered into a Demand Promissory Note (the "2014 Note") with The Bank of New York Mellon, as lender (the "Lender"), relating to the unsecured $363,000 advance. The 2014 Note bears interest at the rate of one-half percent (0.5%) per annum. Pursuant to the terms of the 2014 Note, all amounts outstanding under the 2014 Note will be due and payable in cash on the earliest to occur of (i) the date written demand for payment is made by the Lender or (ii) December 31, 2015. The Trust may prepay any outstanding principal and accrued and unpaid interest under the 2014 Note, in whole or in part, at any time without penalty.

In addition to the 2014 Note, through March 31, 2015, The Bank of New York Mellon has made additional cash advances in the amount of $138,593 to the Trust for the payment of its liabilities and expenses, primarily in connection with the Probate Proceeding. Such cash advances shall bear interest on terms similar to the 2014 Note and will be due and payable in cash on the earliest to occur of (i) the date written demand for payment is made by the Lender or (ii) December 31, 2015.

(11) Subsequent Events

On April 6, 2015, the Trust issued a press release announcing that there would be no trust distribution for the first quarter of 2015 for Unit holders of record on March 31, 2015.

Item 2. Trustee's Discussion and Analysis of Financial Condition and Results of Operations.

Overview

The TEL Offshore Trust, which we refer to herein as the "Trust," was created under the laws of the State of Texas in 1983 and maintains its offices at the office of The Bank of New York Mellon Trust Company, N.A., whom we refer to as the "Corporate Trustee," 919 Congress Avenue, Suite 500, Austin, Texas 78701. The telephone number of the Corporate Trustee is (512) 236-6599. Gary C. Evans, Thomas H. Owen, Jr. and Jeffrey S. Swanson serve as individual trustees of the Trust and are referred to herein as the "Individual Trustees." The Individual Trustees and the Corporate Trustee may be referred to hereinafter collectively as the "Trustees."

The Corporate Trustee does not maintain a website for filings by the Trust with the U.S. Securities and Exchange Commission, which we refer to herein as the "SEC." Electronic filings by the Trust with the SEC are available free of charge through the SEC's website at www.sec.gov. The Trust will also provide paper copies of its recent filing free upon request to the Corporate Trustee.

The principal asset of the Trust consists of a 99.99% interest in the TEL Offshore Trust Partnership, which we refer to herein as the "Partnership." Chevron U.S.A., Inc., or "Chevron," owns the remaining .01% interest in the Partnership and is the Managing General Partner of the Partnership. Until October 27, 2011, the Partnership owned 100% of an overriding royalty interest equivalent to a 25% net profits interest (the "Original Royalty"), in certain oil and gas properties, which we refer to herein as the "Royalty Properties," located offshore Louisiana. The term "Original Royalty" shall refer to the initial 25% net profits interest in the Royalty Properties and the term "Royalty" shall refer to the applicable net profits interest held from time to time by the Partnership following the Royalty Sales (as defined below).

Liquidity and Capital Resources

The Trust's primary source of liquidity and capital is the Royalty income received from its share of the Net Proceeds from the Royalty Properties. Generally, "Net Proceeds" means the amounts received by the owner or owners of the Royalty Properties (the "Working Interest Owners") from the sale of minerals from the Royalty Properties less operating and capital costs incurred, management fees and expense reimbursements owing to the Managing General Partner of the Partnership, applicable taxes other than income taxes, and the Special Cost Escrow account. The Special Cost Escrow account, as more fully detailed in Note 5 to the condensed financial statements, was established for the future costs to be incurred to plug and abandon wells, dismantle and remove platforms, pipelines and other production facilities, and for the estimated amount of future capital expenditures on the Royalty Properties. Net Proceeds do not include amounts received by the Working Interest Owners as advance gas payments, "take- or-pay" payments or similar payments unless and until such payments are extinguished or repaid through the future delivery of gas.

Total future net revenues attributable to the Partnership's interest in the Royalty were estimated at $7.3 million as of October 31, 2014. However, there are not likely to be sufficient Net Proceeds from the Royalty Properties for the Trust to make a regularly scheduled quarterly distribution to Unit holders for the foreseeable future. The Trust has not received a distribution of Net Proceeds since December 2008. Because of the lack of Net Proceeds, the Trust has in the past not had sufficient cash flow to pay expenses on a current basis and as described below, the Trust has been required to borrow funds and to cause the Partnership to sell part of the Original Royalty in order to pay Trust expenses. As of March 31, 2015, including the proceeds from the 2014 Note and additional cash advances from The Bank of New York Mellon, N.A., an affiliate of the Corporate Trustee ("BONYM"), the Trust's available cash was approximately $171,638. Based upon currently estimated expenditures, inclusive of the costs and expenses relating to the Probate Proceeding (as defined below), it is anticipated that the Trust's available cash will be depleted during the second quarter of 2015. In light of the continuing expenses of the Trust and the lack of any distributions and any assurances as to the actual timing of any future distributions, the Trustees have considered the alternatives available to the Trust to obtain funds or to reduce the ongoing costs and expenses of the Trust and after evaluating the alternatives available to the Trust, the Trustees elected to institute the Probate Proceeding described below.

The Trust Agreement provides that, if necessary to provide for the payment of specific liabilities of the Trust then due, the Trustees may without a vote of the Unit holders (a) sell all or a portion of the Trust's interest in the Partnership or any other assets of the Trust for such cash consideration as the Trustees shall deem appropriate, (b) exercise their rights under the Partnership Agreement to dissolve the Partnership, or (c) cause a sale by the Partnership of the overriding royalty interest owned by the Partnership. Additionally, the Trustees, on behalf of the Trust, are authorized to borrow funds, and pledge the assets of the Trust to secure payments of such borrowings, in the event that cash on hand in not sufficient to pay the liabilities of the Trust. In the event that the Trustees borrow funds to pay the liabilities of the Trust, no distributions will be made to the Unit holders until the indebtedness created by such borrowings has been paid in full.

On October 27, 2011, the Trust issued a press release announcing that the Partnership had consummated the sale (the "2011 Royalty Sale") of 20% of the Original Royalty (or 5% of 8/8ths), which generated $1,600,000 in gross proceeds and occurred as part of a formal auction process for the Partnership's overriding royalty interest in the Royalty Properties. The Trust received from the Partnership a distribution of approximately $1,485,581, representing 99.99% of the net proceeds from the sale of $1,486,000. The 2011 Royalty Sale was made to RNR Production, Land and Cattle Company, Inc. ("RNR Production") on October 27, 2011, though the assignment was effective as of August 1, 2011.

In September 2012, the Trustees unanimously determined to suspend future payments of fees to the Trustees effective as of the third quarter of 2012, until a date to be determined in the future by the Trustees. As of December 31, 2013, the amount of such fees was approximately $339,414. The suspended fees were paid in full by the Trust in January 2014 and are included within general and administrative expenses for the three months ended March 31, 2014.

On October 31, 2013, the Trust issued a press release announcing that the Partnership had consummated the sale (the “2013 Royalty Sale” and, together with the 2011 Royalty Sale, the “Royalty Sales”) of 25% of its remaining interest in the Original Royalty (or 5% of 8/8ths), which generated $1,200,000 in gross proceeds and occurred as part of a formal auction process for the Partnership’s remaining overriding royalty interest in the Royalty Properties. The Trust received from the Partnership a distribution of approximately $1,151,885, representing 99.99% of the net proceeds from the sale of $1,152,000. The 2013 Royalty Sale was made to RNR Production on October 31, 2013, though the assignment was effective as of August 1, 2013. The Trust used approximately $300,000 of the net proceeds received in October 2013 to repay the Trust’s indebtedness under a previous note payable to BONYM and used the remaining net proceeds solely for the payment of expenses of the Trust. Following the 2013 Royalty Sale, the Partnership has retained a 60% interest in the Original Royalty, and thus the Partnership will receive in the future only 15% of the Net Proceeds when there are sufficient Net Proceeds for distribution on the Partnership’s Royalty.

In March 2014, the Trustees again unanimously determined to suspend future payments of fees to the Trustees effective as of January 1, 2014, until a date to be determined in the future by the Trustees. As of March 31, 2015, the amount of such fees was approximately $301,814 in the aggregate. Such suspended fees will be recorded as an expense of the Trust when invoiced by the Trustees and paid.

On October 1, 2014, BONYM made a loan to the Trust in the amount of $363,000, and the Corporate Trustee, as the borrower, entered into a Demand Promissory Note (the “2014 Note”) with BONYM, as lender, relating to the unsecured $363,000 advance, which evidenced an extension of credit for borrowed money authorized under Section 6.08 of the Trust Agreement. The 2014 Note bears interest at the rate of one-half percent (0.5%) per annum. Pursuant to the terms of the 2014 Note, all amounts outstanding under the 2014 Note will be due and payable in cash on the earliest to occur of (i) the date written demand for payment is made by BONYM or (ii) December 31, 2015. The Trust may prepay any outstanding principal and accrued and unpaid interest under the 2014 Note, in whole or in part, at any time without penalty. During the quarter ended March 31, 2015, a portion of the proceeds from the 2014 Note were used to pay Trust expenses.

In addition to the 2014 Note, as of March 31, 2015, BONYM has made additional advances in the amount of $138,593 to the Trust for the payment of its liabilities and expenses, primarily in connection with the Probate Proceeding. Although BONYM has no obligation to do so, it is anticipated that BONYM will continue to advance funds to the Trust for the payment of such expenses.

As indicated above, the Trustees have previously authorized the Trust to borrow funds and the Partnership to sell portions of the Original Royalty in an effort to pay the ongoing costs and expenses incurred by the Trust in fulfilling its obligations under the Trust Agreement. As a result of the ongoing costs and expenses of the Trust and the lack of any distributions or assurances of future distributions, on July 10, 2014, the Trustees filed a Petition for Modification and Termination of the Trust (the “Petition”) with the Probate Court of Travis County, Texas (the “Court”). The Petition requests the Court to modify the Trust Agreement to (1) allow for the termination of the Trust by a court order, and (2) allow the Trustees, as necessary to fulfill the purposes of the Trust and without Unit holder approval to (a) sell all or any portion of the Trusts’s interests in the Partnership or any other assets of the Trust, (b) exercise their rights to dissolve the Partnership, or (c) cause the Partnership to sell the Royalty. The goals in filing such probate proceeding (the “Probate Proceeding”) are to permit the Trustees to direct the Partnership to sell the Royalty; to distribute the net proceeds resulting from such sale, after payment of the Trust’s liabilities, to the Unit holders; and, to, thereafter terminate the Partnership and the Trust. It is anticipated that the Trust will fund the costs and expenses of the Probate Proceeding with loans from BONYM. However, BONYM will continue to evaluate the Probate Proceeding and the costs and expenses. There can be no assurances whether the Court will grant the requested relief and, if such relief is granted, when such actions will be completed. The Trustees are currently in the process of giving notice to all Unit holders, which is expected to be completed during the second quarter of 2015. Thereafter, the Trustees will seek the appointment of an ad litem for all Unit holders who have not been personally served. It is anticipated that any loans obtained by the Trust to pay the costs and expenses of the Probate Proceeding will be repaid from any proceeds received by the Trust, including any proceeds received upon any sale of the remaining Royalty and, as a result, there can be no assurances as to amount of net proceeds resulting from any such sale of the Royalty that may be available for distribution to the Unit holders.

On October 7, 2008, the Trust announced that production from the two most significant oil and gas properties associated with the Trust had ceased following damage inflicted by Hurricane Ike in September 2008. On December 19, 2008, the Trust announced its fourth quarter distribution of approximately $0.7 million, which was paid on January 9, 2009. Based on the damage caused by Hurricane Ike, the Trust's scheduled distribution for the fourth quarter of 2008 was severely negatively impacted and no distributions have been made to Unit holders since January 9, 2009. In the fourth quarter of 2010, Chevron withdrew $4,304,894 from the Special Cost Escrow account of the Working Interest Owners (a reserve fund for certain costs) to cover expenses incurred in connection with the plugging and abandonment of Eugene Island 339, which served to reduce the amount by which production costs exceeded the proceeds from production; however, additional deposits to the Special Cost Escrow account would be required in future periods in accordance with the terms of the Conveyance if, and when, Net Proceeds would otherwise be payable on the Partnership's interest in the Royalty. As a result of the damage inflicted by Hurricane Ike, Net Proceeds will continue to be severely impacted by reduced production, from historical levels, and the amount of expenditures incurred that are associated with such damages, including any remaining expenditures required to plug and abandon the wells on Eugene Island 339.

The platforms and wells on Eugene Island 339 were completely destroyed by Hurricane Ike. Chevron has completed the work associated with the wells on Eugene Island 339 and informed the Trust that the aggregate cost to the Original Royalty to plug and abandon the wells, remove and abandon platforms and infrastructure and remediate the surface subject to the overriding royalty interest on Eugene Island 339 was approximately $19.8 million and that no further expenses of this nature relating to prior hurricane damage are expected to be incurred. In December 2009, Chevron and Arena Offshore, LP ("Arena") entered into a participation agreement to assist in the redevelopment as a farmout of portions of Eugene Island 338 and 339 (the participation agreement, as amended, the "Arena Agreement"). Pursuant to the terms of the Arena Agreement, Arena had the right to earn an assignment of 65% of Chevron's working interests in Eugene Island 338 and Eugene Island 339 following completion of certain drilling and development operations. Following completion of the first well on Eugene Island 339 by Arena and other drilling and development operations in the fourth quarter of 2012, Chevron assigned 65% of Chevron's working interests in Eugene Island 338 and Eugene Island 339 to Arena, effective as of December 15, 2009, the effective date of the Arena Agreement. In accordance with the Arena Agreement, the working interest assigned to Arena is not burdened by the Royalty, and the Royalty held by the Partnership with respect to such properties has been reduced proportionately. As a result of such assignment, the Royalty held by the Partnership on Eugene Island 339 has been reduced by 65%. See "—Operations" for a more detailed discussion of Eugene Island 339.

Production at Ship Shoal 182/183 ceased following damage inflicted by Hurricane Ike in September 2008. While the hurricane caused limited surface damage to the facilities at Ship Shoal 182/183, all of the wells at Ship Shoal 182/183 were shut-in following hurricane-related damage to a third-party transporter's natural gas pipeline. Production has since been restored at Ship Shoal 182/183. See "—Operations" for a more detailed discussion of Ship Shoal 182/183.

In addition, production from West Cameron 643 and East Cameron 371 ceased following damage inflicted by Hurricane Ike in September 2008 to third-party transporters' pipelines. The lease for West Cameron 643 expired on May 31, 2010 and the lease for East Cameron 371 expired on March 31, 2010. Plugging and abandoning of the wells at West Cameron 643 was completed in October 2012. The abandonment work for East Cameron 371 has been completed.

Chevron reached settlements that provided Chevron with insurance proceeds associated with damages that Chevron's assets sustained from Hurricane Ike. The allocated portion thereof with respect to the Partnership's interest in Eugene Island 339, as a Royalty Property, was approximately $781,000. Chevron applied $400,000 thereof in the first quarter of 2011 and applied the remaining amount of approximately $381,000 in the fourth quarter of 2012. All such allocated insurance proceeds were applied to the Partnership's portion of the aggregate cost to plug and abandon the wells subject to the Royalty on Eugene Island 339. Chevron has completed the work associated with the wells on Eugene Island 339 and informed the Trust that the aggregate cost to the Original Royalty to plug and abandon the wells, remove and abandon platforms and infrastructure and remediate the surface subject to the overriding royalty interest on Eugene Island 339 was approximately $19.8 million and that no further expenses of this nature relating to prior hurricane damage are expected to be incurred. If Production Costs of the Royalty Properties exceed the Gross Proceeds from the Royalty Properties, the Trust will not receive Net Proceeds until future proceeds from production exceed the total of the excess costs plus accrued interest at a rate equal to one-fourth of (i) one-half of one percent plus (ii) the median between the prime interest rate at the end of a quarterly period in which there are excess costs and the prime interest rate at the end of the preceding quarterly period, during the deficit period. As a result of the damage inflicted by Hurricane Ike, the Trust has not received Net Proceeds since December 2008. As of January 31, 2015, aggregate development and production costs for the Royalty Properties since November 2008 have exceeded the related proceeds of production from the Royalty Properties by approximately $2.3 million, net to the entire Original Royalty (or $1.4 million applicable to the Trust). The excess development and production costs have decreased from $2.8 million, as of October 31, 2014 to $2.3 million, net to the entire Original Royalty, as of January 31, 2015, reflecting increased production from the Royalty Properties. While Chevron has not withdrawn any funds from the Special Cost Escrow Account since the fourth quarter of 2010, additional deposits to the Special Cost Escrow account would be required in future periods in accordance with the terms of the Conveyance if, and when, Net Proceeds would otherwise be payable on the Royalty. Accordingly, there will not be sufficient Net Proceeds from the Royalty Properties to make distributions for some period of time in the future. At this time, the ultimate outcome of these various matters cannot be determined. See "—Operations"

Substantial uncertainties exist with regard to future oil and gas prices, which are subject to material fluctuations due to changes in production levels and pricing and other actions taken by major petroleum producing nations, as well as the regional supply and demand for oil and gas, worldwide political conditions, weather, industrial growth, conservation measures, competition, economic conditions generally and other variables.

In accordance with the provisions of the Trust Agreement, generally all Net Proceeds received by the Trust, net of Trust general and administrative expenses and any cash reserves established for the payment of contingent or future obligations of the Trust, are distributed currently to the Unit holders. Historically the Trust generally maintained a cash reserve, equal to approximately three times the average annual expenses of the Trust during each of the then past three years, to provide for future administrative expenses in connection with the winding up of the Trust. However, as a result of the damage inflicted upon certain of the Royalty Properties by Hurricane Ike in September 2008, the Trust has not received sufficient Net Proceeds to maintain the reserve at such level. During the quarter ended March 31, 2015, the Trust utilized $94,604 of the proceeds from the 2014 Note and cash advances from BONYM to pay for Trust expenses. As of March 31, 2015, the reserve balance was $0. Including the proceeds from the 2014 Note, and cash advances from BONYM, the Trust's available cash was approximately $171,638 at March 31, 2015.

The accompanying condensed financial statements have been prepared assuming that the Trust will continue as a going concern. Financial statements prepared on the going concern basis assume the realization of assets and the settlement of liabilities in the normal course of business. The lack of Net Proceeds and the inability to maintain adequate cash reserves raise substantial doubt about the Trust's ability to continue as a going concern. Certain potential alternatives available to the Trustees are described in Note 6 to the condensed financial statements. The condensed financial statements do not include any adjustments that might result from the outcome of this uncertainty. See Notes 2 and 6 to the condensed financial statements.

Future Net Revenues and Termination of the Trust

Based on a reserve study provided to Chevron, as the Managing General Partner of the Partnership, by DeGolyer and MacNaughton, independent petroleum engineers, as of October 31, 2014 future net revenues attributable to the Trust's royalty interests were estimated at $7.3 million. Estimates of proved oil and gas reserves attributable to the Partnership's royalty interest are based on existing economic and operating conditions in effect at October 31, 2014 in order to correspond with distributions to the Trust. Such reserve study also indicates that approximately 69% of the future net revenues from the Royalty Properties are expected to be received by the Trust by October 31, 2017. The reserve study does include projected reserves attributable to the four wells drilled by Arena on Eugene Island 339 but does not include any capital expenditures for any redevelopment of Eugene Island 339. Because the Trust will terminate in the event estimated future net revenues attributable to the Partnership's interest in the Royalty fall below $1.2 million (assuming no further sales of any interests in the Royalty), it would be possible for the Trust to terminate even though some or all of the Royalty Properties continued to have remaining productive lives. Upon termination of the Trust, the Trustees will sell for cash all of the assets held in the Trust estate and make a final distribution to Unit holders of any funds remaining after all Trust liabilities have been satisfied. The estimates of future net revenues discussed above are subject to large variances from year to year and should not be construed as exact. There are numerous uncertainties present in estimating future net revenues for the Royalty Properties. The estimate may vary depending on changes in market prices for crude oil and natural gas, the recoverable reserves, annual production and costs assumed by DeGolyer and MacNaughton. In addition, future economic and operating conditions as well as results of future drilling plans may cause significant changes in such estimate. The discussion set forth above is qualified in its entirety by reference to the 2014 10-K. The 2014 10-K is available at the website of the Securities and Exchange Commission ("SEC") at *www.sec.gov* or upon request from the Corporate Trustee.

Special Cost Escrow Account

The Conveyance provides for reserving funds for estimated future “Special Costs” of plugging and abandoning wells, dismantling platforms and other costs of abandoning the Royalty Properties, as well as for the estimated amount of future drilling projects and other capital expenditures on the Royalty Properties. As provided in the Conveyance, the amount of funds to be reserved is determined based on factors including estimates of aggregate future production costs, aggregate future Special Costs, aggregate future net revenues and actual current net proceeds. Deposits into this account reduce current distributions and are placed in an escrow account and invested in short-term certificates of deposit. Such account is herein referred to as the “Special Cost Escrow” account. The Trust’s share of interest generated from the Special Cost Escrow account serves to reduce the Trust’s share of allocated production costs. Special Cost Escrow funds will generally be utilized to pay Special Costs to the extent there are not adequate current net proceeds to pay such costs. Special Costs that have been paid are no longer included in the Special Cost Escrow calculation. Deposits to the Special Cost Escrow account will generally be made when the balance in the Special Cost Escrow account is less than 125% of estimated future Special Costs and there is a Net Revenues Shortfall (a calculation of the excess of estimated future costs over estimated future net revenues pursuant to a formula contained in the Conveyance). When there is not a Net Revenues Shortfall, amounts in the Special Cost Escrow account will generally be released, to the extent that Special Costs have been incurred. Amounts in the Special Cost Escrow account will also be released when the balance in such account exceeds 125% of estimated future Special Costs. In the first quarter of 2015, there were no funds released or escrowed from the Special Cost Escrow account. As of March 31, 2015, $1,000 remained in the Special Cost Escrow account. The funds held in the Special Cost Escrow account are not reflected in the condensed financial statements of the Trust. The discussion of the terms of the Conveyance and Special Cost Escrow account contained herein is qualified in its entirety by reference to the Conveyance itself, which is an exhibit to this Form 10-Q and is available upon request from the Corporate Trustee.

Aggregate development and production costs in excess of the related proceeds for the royalty properties, as of January 31, 2015, were approximately $2.3 million, net to the entire Royalty ($1.4 million applicable to the Trust); however, additional deposits to the Special Cost Escrow account would be required in future periods in accordance with the Conveyance if, and when, Net Proceeds would otherwise be payable on the Royalty. During the three months ended March 31, 2015 and March 31, 2014, respectively, there were no funds released from or escrowed into the Special Cost Escrow account. As of March 31, 2015, $1,000 remained in the Special Cost Escrow account.

In connection with the Royalty Sales, the Partnership has assigned an aggregate 40% of its rights and obligations with respect to the Special Cost Escrow account.

Chevron, in its capacity as Managing General Partner of the Partnership, has advised the Trust that additional deposits to the Special Cost Escrow account will be required in future periods in connection with other production costs, other abandonment costs, other capital expenditures and changes in the estimates and factors described above. Such deposits could result in a significant reduction in Royalty income in the periods in which such deposits are made.

Three Months Ended March 31, 2015 and 2014

Royalty Trust Comparison

Royalty income was $0 for each of the three months ended March 31, 2015 and 2014. Gross proceeds for the underlying Royalty Properties exceeded development and production costs by $486,826, or $292,096 attributable to the Trust, for the production period of November and December 2014 and January 2015 attributable to the three months ended March 31, 2015 and by $426,454, or $63,968 attributable to the Trust for the production period of November and December 2013 and January 2014 attributable to the three months ended March 31, 2014. The Net Proceeds were applied to reduce the accumulated excess cost carry forward, which represents the amount by which the aggregate development and production costs for the Royalty Properties since November 2008 have exceeded the related proceeds of the protection, and as a result there was no royalty income for the quarters ended March 31, 2015 and 2014.

General and administrative expenses for the Trust were $94,604 for the three months ended March 31, 2015 compared to $488,925 for the three months ended March 31, 2014. The decrease is due, in part, to the timing of the recording of expenses, and the $339,414 payment of the suspended Trustee fees paid in January 2014.

The reserve for future Trust expenses did not change from December 31, 2014 to March 31, 2015.

There was no distributable income for each of the three months ended March 31, 2015 and March 31, 2014 and therefore no distributions to Unit holders.

For the three months ended March 31, 2015 and March 31, 2014, the Trust had undistributed net income of $292,096 and $63,968, respectively, representing the Trust's portion of the undistributed net income of $1,947,304 and $426,454 associated with the Royalty Properties for the three months ended March 31, 2015 and 2014. As of January 31, 2015, the cumulative undistributed net loss was $2.3 million, net to the entire Original Royalty ($1.4 million net to the Trust). Undistributed net loss represents the amount of development and production costs associated with the Royalty that exceed the proceeds of production from the Royalty Properties during the period. An undistributed net loss is carried forward and offset, in future periods, by positive proceeds earned by the related Working Interest Owner(s). The Trust will not receive Net Proceeds until future proceeds from production exceed the total of the excess costs plus applicable accrued interest.

Underlying Properties Comparison

The following financial and operational information has been based on information provided to the Corporate Trustee by the Managing General Partner. The Trustees have no control over these operations or internal controls relating to this information.

Volumes and dollar amounts discussed below represent amounts recorded by the Working Interest Owners unless otherwise specified.

Natural Gas and Gas Products

Gas revenues increased $226,173, or 245%, to $318,440 in the first quarter of 2015 from $92,267 in the first quarter of 2014. Gas volumes during the first quarter of 2015 increased 284% to 79,063 Mcf from 20,587 Mcf in the first quarter of 2014. The average price received for natural gas decreased approximately 13% from an average price of $4.55 per Mcf in the first quarter of 2014 to $3.95 per Mcf in the first quarter of 2015, excluding the impact of the adjustments for Eugene Island 339 and Eugene Island 342. Gas products revenue decreased $12,635, or 30%, to $29,768 in the first quarter of 2015 from $42,403 in the first quarter of 2014. Gas products volumes during the first quarter of 2015 increased 26% to 65,517 gallons, compared to 51,843 gallons in the first quarter of 2014.

Crude Oil and Condensate

Crude oil and condensate revenues increased $367,830, or 16%, to $2,616,204 in the first quarter of 2015 from $2,248,374 in the first quarter of 2014. The increase in revenues is the result of an increase in production for Ship Shoal 182/183 for the first quarter of 2015. Oil volumes increased 53% from 22,568 barrels in the first quarter of 2014 to 34,539 barrels in the first quarter of 2015. The average price received for crude oil and condensate production decreased approximately 22%, or $21.31, to $77.64 per barrel in the first quarter of 2015 from $98.95 per barrel in the first quarter of 2014, excluding the impact of the adjustments for Eugene Island 339 and Eugene Island 342.

Capital Expenditures

Capital expenditures decreased by $141,462, or 99%, from $141,634 in the first quarter of 2014 to $172 in the first quarter of 2015. The higher amount of capital expenditures during the first quarter of 2014 relates primarily to facility improvement projects and drilling and completion costs associated with a well at Ship Shoal 182/183.

Production Expenses

Production expenses decreased by $798,020, or 44%, from $1,814,956 in the first quarter of 2014 to $1,016,936 in the first quarter of 2015. The decrease in operating expenses is due to maintenance projects at Ship Shoal 169 in the first quarter of 2014 as compared to the first quarter of 2015.

Special Cost Escrow Account

In the first quarter of 2015, there were no funds released from or escrowed into the Special Cost Escrow account. As of March 31, 2015, $1,000 remained in the Special Cost Escrow account. The funds held in the Special Cost Escrow account are not reflected in the condensed financial statements of the Trust. The Special Cost Escrow account is set aside for estimated abandonment costs and future capital expenditures, as provided for in the Conveyance. For additional information relating to the Special Cost Escrow account, see "—Special Cost Escrow Account" above.

Summary By Property

Listed below is a summary of operations of the principal Royalty Properties for the first quarter of 2015 as compared to operations for the first quarter of 2014 based on gross revenues generated during these periods combined.

Eugene Island 339

Net crude oil revenues decreased from $732,405 in the first quarter of 2014 to $695,235 in the first quarter of 2015, due to a decrease in the average crude oil price received from $98.72 per barrel in the first quarter of 2014 to $81.19 per barrel in the first quarter of 2015. This decrease was partially offset by an increase in net crude oil production from 7,419 barrels in the first quarter of 2014 to 8,563 barrels in the first quarter of 2015. Gas revenues decreased from $49,018 in the first quarter of 2014 to $21,134 in the first quarter of 2015, due to a decrease in gas production from 11,477 Mcf in the first quarter of 2014 to 4,679 Mcf in the first quarter of 2015. The decrease in volumes is primarily attributable to the K-2 well being temporarily shut in for maintenance. Capital expenditures were $0 in the first quarter of 2014 and the first quarter of 2015. Operating expenses decreased from $35,369 in the first quarter of 2014 to $18,465 in the first quarter of 2015 due primarily to lower production in the first quarter of 2015 as compared to the first quarter of 2014.

Ship Shoal 182/183

Net crude oil revenues increased from $1,364,701 in the first quarter of 2014 to $2,044,329 in the first quarter of 2015, due to an increase in net crude oil production from 13,646 barrels in the first quarter of 2014 to 26,653 barrels in the first quarter of 2015. The increase in volumes was primarily due to multiple shut ins for facility improvement projects during the first quarter of 2014. This increase was partially offset by a decrease in the average crude oil price received from $100.01 per barrel in the first quarter of 2014 to $76.70 per barrel for the same period in 2015. Gas revenues increased from $31,875 in the first quarter of 2014 to $265,971 in the first quarter of 2015, due to an increase in gas production from 5,850 Mcf in the first quarter of 2014 to 67,982 Mcf in the first quarter of 2015 as a result of the pipeline being fixed and production restored back online, increasing production. This increase was partially offset by a decrease in the average gas revenue price received from $5.45 per Mcf in the first quarter of 2014 to $3.91 per Mcf for the same period in 2015. Capital expenditures decreased from $139,512 in the first quarter of 2014 to $332 in the first quarter of 2015. Operating expenses decreased from $1,635,075 in the first quarter of 2014 to $871,063 for the same period in 2015 due to several maintenance projects during the first quarter of 2014.

South Timbalier 36/37

Net crude oil revenues increased from $91,588 in the first quarter of 2014 to $112,474 for the same period in 2015 due primarily to an increase in oil production volumes from 926 barrels in the first quarter of 2014 to 1,520 barrels in the first quarter of 2015. This increase was partially offset by a decrease in the average crude oil price received from $98.96 per barrel in the first quarter of 2014 to $73.97 per barrel in the first quarter of 2015. Gas revenues decreased from $11,374 in the first quarter of 2014 to $4,196 in the first quarter of 2015 due to a decrease in gas production from 3,259 Mcf in the first quarter of 2014 to 1,046 Mcf in the first quarter of 2015. These decreases were partially offset by an increase in the average natural gas price received from $3.49 per Mcf in the first quarter of 2014 to $4.01 per Mcf in the first quarter of 2015. Capital expenditures decreased from an expense of $2,122 in the first quarter of 2014 to a benefit of $160 in the first quarter of 2015 primarily due to the sale of some materials at South Timbalier 36/37. Operating expenses decreased from $18,114 in the first quarter of 2014 to $11,441 in the first quarter of 2015 due to maintenance repairs conducted during the first quarter of 2014.

Eugene Island 342

Net crude oil revenues decreased from $59,681 in the first quarter of 2014 to negative $235,835 in the first quarter of 2015. This decrease is primarily due to a prior period adjustment in net crude oil production from 578 barrels in the first quarter of 2014 to negative 2,198 barrels in the first quarter of 2015. Gas revenues were $0 and gas production was 0 Mcf in the first quarter of 2014, compared to gas revenues of $27,139 and gas production of 5,356 Mcf in the first quarter of 2015. As the underlying interest in Eugene Island 342 is an overriding royalty interest, there were no capital or operating expenses recorded in the first quarter of 2015 and 2014.

Operations

The following operational information has been based on information provided to the Corporate Trustee by Chevron as the Managing General Partner of the Partnership. The Trustees have no control over these operations or internal controls relating to this information.

The platforms and wells on Eugene Island 339 were completely destroyed by Hurricane Ike in September 2008. Chevron has completed the work associated with the wells on Eugene Island 339 and informed the Trust that the aggregate cost to the Original Royalty to plug and abandon the wells, remove and abandon platforms and infrastructure and remediate the surface subject to the overriding royalty interest on Eugene Island 339 was approximately $19.8 million and that no further expenses of this nature relating to prior hurricane damage are expected to be incurred.

Generally, if production ceases from an outer continental shelf lease, like that for Eugene Island 339, production must be restored or drilling operations must commence within 180 days of the cessation of production (which was in early March 2009 with respect to Eugene Island 339 given the cessation of production in September 2008 resulting from Hurricane Ike), or the lease will be terminated. Alternatively, an operator of a lease may request a Suspension of Production (each, an "SOP"), that, if approved by the regional supervisor of the Bureau of Ocean Energy Management allows additional time to restore production in the event of certain circumstances, such as hurricanes and other events beyond the control of the operator. Although Chevron successfully obtained a series of SOPs and, with the participation of Arena, obtained additional SOPs resulting in the restoration of limited production at Eugene Island 339, other Working Interest Owners have been unable to timely restore production or obtain an SOP and as a result, many of the leases covering the Royalty Properties have been terminated or expired thereby reducing the proceeds payable to the Trust.

On December 15, 2009, Chevron entered into the Arena Agreement with Arena to assist in the redevelopment as a farmout of portions of Eugene Island 338 and 339. Pursuant to the terms of the Arena Agreement, Arena could earn an assignment of 65% of Chevron's working interests in Eugene Island 338 and Eugene Island 339. Chevron holds a 50% interest in Eugene Island 339, which interest is included in the 5500' and the 4500' sand units; 42.05% of all production from the 5500' sand unit is allocated to Eugene Island 339 and 38.50% of the gas production and 24.44% of the oil production from the 4500' sand unit is allocated to Eugene Island 339. Pursuant to the terms of the Conveyance, Chevron may enter into a farmout agreement whereby Chevron assigns any portion of its interest in the Royalty Properties free and clear of the Original Royalty, and the Original Royalty will be reduced in the same proportion as that in which the Royalty Property is reduced. Under the terms of the Conveyance, a "farmout agreement" is defined as an agreement with a third party requiring or permitting the performance of drilling or development operations on a Royalty Property, and for which all or substantially all of the consideration is the transfer of an interest in a Royalty Property. On August 4, 2012, Arena completed installation of the remaining topside decks of the structure and on August 16, 2012, Arena commenced mobilization of the H&P 100 platform rig components. On September 28, 2012, Arena spud the OCS-G 2318 Well No. K002 and production from this well was realized in the fourth quarter of 2012. Pursuant to the terms of the Arena Agreement, following completion of the well and the other drilling and development operations, Chevron assigned 65% of Chevron's working interests in Eugene Island 338 and Eugene Island 339 to Arena, effective as of December 15, 2009, the effective date of the Arena Agreement. In accordance with the Arena Agreement, the working interest assigned to Arena is not burdened by the Original Royalty, and the Royalty held by the Partnership with respect to such properties has been reduced proportionately. As a result of such assignment, the Royalty held by the Partnership on Eugene Island 339 has been reduced by 65%.

Production at Ship Shoal 182/183 ceased following damage inflicted by Hurricane Ike in September 2008. While the hurricane caused limited surface damage to the facilities at Ship Shoal 182/183, all of the wells at Ship Shoal 182/183 were shut-in following hurricane-related damage to a third-party transporter's natural gas pipeline and production has since been restored.

In addition, production from West Cameron 643 and East Cameron 371 ceased following damage inflicted by Hurricane Ike in September 2008 to third-party transporters' pipelines. The lease for West Cameron 643 expired on May 31, 2010 and the lease for East Cameron 371 expired on March 31, 2010. Plugging and abandoning of the wells at West Cameron 643 was completed in October 2012. Field abandonment work for East Cameron 371, including the related wells, equipment platforms and any field infrastructure, remains to be completed.

Overview of Production, Prices and Royalty Income

The following schedule provides a summary of the volumes and weighted average prices for crude oil and condensate and natural gas recorded by the Working Interest Owners for the Royalty Properties, as well as the Working Interest Owners' calculations of the Net Proceeds and Royalties paid to the Trust during the periods indicated. The following information for the three months ended March 31, 2014 includes the effect of the audit adjustments of Eugene Island 339 and Eugene Island 342.

	Royalty Properties Three Months Ended March 31,(1)	
	2015	2014
Crude oil and condensate (bbls)	34,539	22,568
Natural gas and gas products (Mcfe)	89,982	29,227
Crude oil and condensate average price, per bbl(2)	$75.75	$99.63
Natural gas average price, per Mcf (excluding gas products)(3)	$4.03	$4.48
Crude oil and condensate revenues	$2,616,204	$2,248,374
Natural gas and gas products revenues	348,207	134,670
Production expenses	(1,016,936)	(1,814,956)
Capital expenditures	(172)	(141,634)
Interest		
Undistributed net loss (income)(4)	(1,947,303)	(426,454)
Refund of (provision for) Special Cost Escrow	—	—
Net Proceeds	—	—
Royalty interest	X15%	X15%
Partnership share	—	—
Trust interest	x99.99%	x99.99%
Trust share of Royalty Income(5)	$—	$—

(1) Amounts are based on production for the three-month period ended January 31 of each year, respectively, and include the results of the adjustments for Eugene Island 339 and Eugene Island 342.

(2) Excluding the adjustments, the average price was $77.64 and $98.95 per barrel, respectively.

(3) Excluding the adjustments, the average price was $3.95 and $4.55 per Mcf, respectively.

(4) Undistributed net loss represents the amount of development and production costs associated with the Royalty that exceed the proceeds of production from the Royalty Properties during the period. An undistributed net loss is carried forward and offset, in future periods, by positive proceeds earned by the related Working Interest Owner(s). The Trust will not receive Net Proceeds until future proceeds from production exceed the total of the excess costs plus applicable accrued interest. Undistributed net income represents positive Net Proceeds, generated during the respective period, but not distributed by the Working Interest Owners.

(5) See "Trustee's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources" and Note 4 to the Notes to the Condensed Financial Statements under Item 1 of Part I of this Form 10-Q for a discussion regarding uncertainty of distributions.

Critical Accounting Policies

Disclosure of critical accounting policies and the more significant judgments and estimates used in the preparation of the Trust's financial statements are included in Item 7 of the 2014 10-K. There have been no significant changes to the critical accounting policies during the three months ended March 31, 2015.

New Accounting Pronouncements

There were no accounting pronouncements issued during the three months ended March 31, 2015 applicable to the Trust or its condensed financial statements.

Off-Balance Sheet Arrangements

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

The only assets of and sources of income to the Trust are cash and the Trust's interest in the Partnership, which is the holder of the Royalty. Consequently, the Trust is exposed to market risk associated with the Royalty from fluctuations in oil and gas prices. Reference is also made to Note 2 of the Notes to Condensed Financial Statements included in Item 1 of this Form 10-Q.

The Trust may borrow money to pay expenses of the Trust. Additionally, if development and production costs of the Royalty exceed the proceeds of production from the Royalty Properties, the Trust will not receive Net Proceeds until future proceeds from production exceed the total of the excess costs plus accrued interest, at a rate equal to one-fourth of (i) one-half of one percent plus (ii) the median between the prime interest rate at the end of a quarterly period in which there are excess costs and the prime interest rate at the end of the preceding quarterly period, during the deficit period. Consequently, the Trust will be exposed to interest rate market risk should it borrow money to pay expenses and to the extent that development and production costs of the Royalty exceed the proceeds of production from the Royalty Properties.

Item 4. Controls and Procedures.

Evaluation of disclosure controls and procedures. The Corporate Trustee maintains disclosure controls and procedures designed to ensure that information required to be disclosed by the Trust in the reports that it files or submits under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and regulations. Disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed by the Trust is accumulated and communicated by Chevron, as the Managing General Partner of the Partnership, and the Working Interest Owners to the Corporate Trustee of the Trust, and its employees who participate in the preparation of the Trust's periodic reports as appropriate to allow timely decisions regarding required disclosure.

As of the end of the period covered by this report, the Corporate Trustee carried out an evaluation of the Trust's disclosure controls and procedures. Michael J. Ulrich, as Trust Officer of the Corporate Trustee, has concluded that the disclosure controls and procedures of the Trust are effective.

Due to the contractual arrangements of (i) the Trust Agreement, (ii) the Partnership Agreement and (iii) the rights of the Partnership under the Conveyance regarding information furnished by the Working Interest Owners, the Trustees rely on (A) information provided by the Working Interest Owners, including historical operating data, plans for future operating and capital expenditures, reserve information and information relating to projected production, (B) information from the Managing General Partner of the Partnership, including information that is collected from the Working Interest Owners, and (C) conclusions and reports regarding reserves by the Trust's independent reserve engineers. See Item 1A. Risk Factors "—The Trustees and the Unit holders have no control over the operation or development of the Royalty Properties and have little influence over operation or development" and "The Trustees rely upon the Working Interest Owners and Managing General Partner for information regarding the Royalty Properties" in the 2014 Form 10-K for a description of certain risks relating to these arrangements and reliance on and applicable adjustments to operating information when reported by the Working Interest Owners to the Corporate Trustee and recorded in the Trust's results of operation.

Changes in Internal Control Over Financial Reporting. During the three months ended March 31, 2015, there has been no change in the Trust's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the Trust's internal control over financial reporting. The Corporate Trustee notes for purposes of clarification that it has no authority over, and makes no statement concerning, the internal control over financial reporting of the Working Interest Owners or the Managing General Partner of the Partnership.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings.

On July 10, 2014, the Trustees filed a Petition for Modification and Termination of the Trust (the "Petition") with the Probate Court of Travis County, Texas (the "Court"). The Petition requests the Court to modify the Trust Agreement to (1) allow for the termination of the Trust by a court order, and (2) allow the Trustees, as necessary to fulfill the purposes of the Trust and without unitholder approval to (a) sell all or any portion of the Trust's interests in the Partnership or any other assets of the Trust, (b) exercise their rights to dissolve the Partnership, or (c) cause the Partnership to sell the Royalty. The goals in filing such probate proceeding are to permit the Trustees to direct the Partnership to sell the Royalty; to distribute the net proceeds resulting from such sale, after payment of the Trust's liabilities, to the Trust's unitholders; and, to, thereafter terminate the Partnership and the Trust. The Trustees are currently in the process of giving notice to all unitholders, which is expected to be completed during the second quarter of 2015. Thereafter, the Trustees will seek the appointment of an ad litem for all unitholders who have not been personally served. There can be no assurances whether the Court will grant the requested relief and, if such relief is granted, when such actions will be completed.

Item 1A. Risk Factors.

There have not been any material changes from the risk factors previously disclosed in the Trust's response to Item 1A. to Part 1 of the 2014 10-K.

Item 6. Exhibits.

(Asterisk indicates exhibit previously filed with the Securities and Exchange Commission and incorporated herein by reference.)

			SEC File or Registration Number	Exhibit Number
4(a)*	—	Trust Agreement dated as of January 1, 1983, among Tenneco Offshore Company, Inc., Texas Commerce Bank National Association, as corporate trustee, and Horace C. Bailey, Joseph C. Broadus and F. Arnold Daum, as individual trustees (Exhibit 4(a) to Form 10-K for the year ended December 31, 1992 of TEL Offshore Trust)	0-06910	4(a)
4(b)*	—	Agreement of General Partnership of TEL Offshore Trust Partnership between Tenneco Oil Company and the TEL Offshore Trust, dated January 1, 1983 (Exhibit 4(b) to Form 10-K for year ended December 31, 1992 of TEL Offshore Trust)	0-06910	4(b)
4(c)*	—	Conveyance of Overriding Royalty Interests from Exploration I to the Partnership (Exhibit 4(c) to Form 10-K for year ended December 31, 1992 of TEL Offshore Trust)	0-06910	4(c)
4(d)*	—	Amendments to TEL Offshore Trust Agreement, dated December 7, 1984 (Exhibit 4(d) to Form 10- K for year ended December 31, 1992 of TEL Offshore Trust)	0-06910	4(d)
4(e)*	—	Amendment to the Agreement of General Partnership of TEL Offshore Trust Partnership, effective as of January 1, 1983 (Exhibit 4(e) to Form 10-K for the year ended December 31, 1992 of TEL Offshore Trust)	0-06910	4(e)
10(a)*	—	Purchase Agreement, dated as of December 7, 1984 by and between Tenneco Oil Company and Tenneco Offshore II Company (Exhibit 10(a) to Form 10-K for year ended December 31, 1992 of TEL Offshore Trust)	0-06910	10(a)
10(b)*	—	Consent Agreement, dated November 16, 1988, between TEL Offshore Trust and Tenneco Oil Company (Exhibit 10(b) to Form 10-K for year ended December 31, 1988 of TEL Offshore Trust)	0-06910	10(b)

			SEC File or Registration Number	Exhibit Number
10(c)*	—	Assignment and Assumption Agreement, dated November 17, 1988, between Tenneco Oil Company and TOC- Gulf of Mexico Inc. (Exhibit 10(c) to Form 10-K for year ended December 31, 1988 of TEL Offshore Trust)	0-06910	10(c)
10(d)*	—	Gas Purchase and Sales Agreement Effective September 1, 1993 between Tennessee Gas Pipeline Company and Chevron U.S.A. Production Company (Exhibit 10(d) to Form 10-K for year ended December 31, 1993 of TEL Offshore Trust)	0-06910	10(d)
31	—	Certification furnished pursuant to Section 302 of the Sarbanes-Oxley Act of 2002		
32	—	Certification furnished pursuant to Section 906 of the Sarbanes-Oxley Act of 2002		

SIGNATURES

Pursuant to the requirements 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.

TEL OFFSHORE TRUST

By: The Bank of New York Mellon
Trust Company, N.A.
Corporate Trustee

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

Date: May 14, 2015

The Registrant, TEL Offshore Trust, has no principal executive officer, principal financial officer, board of directors or persons performing similar functions. Accordingly, no additional signatures are available and none have been provided.

Exhibit 31

CERTIFICATION

I, Michael J. Ulrich, certify that:

1. I have reviewed this quarterly report on Form 10-Q of TEL Offshore Trust, for which The Bank of New York Mellon Trust Company, N.A. acts as Corporate Trustee;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, distributable income and changes in trust corpus of the registrant as of, and for, the periods presented in this report;

4. I am responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and I have:

   a) Designed such disclosure controls and procedures, or caused such controls and procedures to be designed under my supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to me by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under my supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report my conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. I have disclosed, based on my most recent evaluation of internal control over financial reporting, to the registrant's auditors:

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves any persons who have a significant role in the registrant's internal control over financial reporting.

In giving the foregoing certifications in paragraphs 4 and 5, I have relied to the extent I consider reasonable on information provided to me by the Working Interest Owners and the Managing General Partner of the TEL Offshore Trust Partnership, in which the registrant owns a 99.99% interest.

Date: May 14, 2015

/s/ MICHAEL J. ULRICH

Michael J. Ulrich
Vice President
The Bank of New York Mellon Trust Company, N.A.

Exhibit 32

Securities and Exchange Commission
Judiciary Plaza
450 Fifth Street, N.W.
Washington, D.C. 20549

Re: Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

Ladies and Gentlemen:

In connection with the Quarterly Report of TEL Offshore Trust (the “Trust”) on Form 10-Q for the quarterly period ended March 31, 2015 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), the undersigned, not in its individual capacity but solely as the trustee of the Trust, certifies pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to its knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Trust.

The above certification is furnished solely pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. 1350) and is not being filed as part of the Report or as a separate disclosure document.

The Bank of New York Mellon
Trust Company, N.A.,
Corporate Trustee for TEL Offshore Trust

Date: May 14, 2015

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