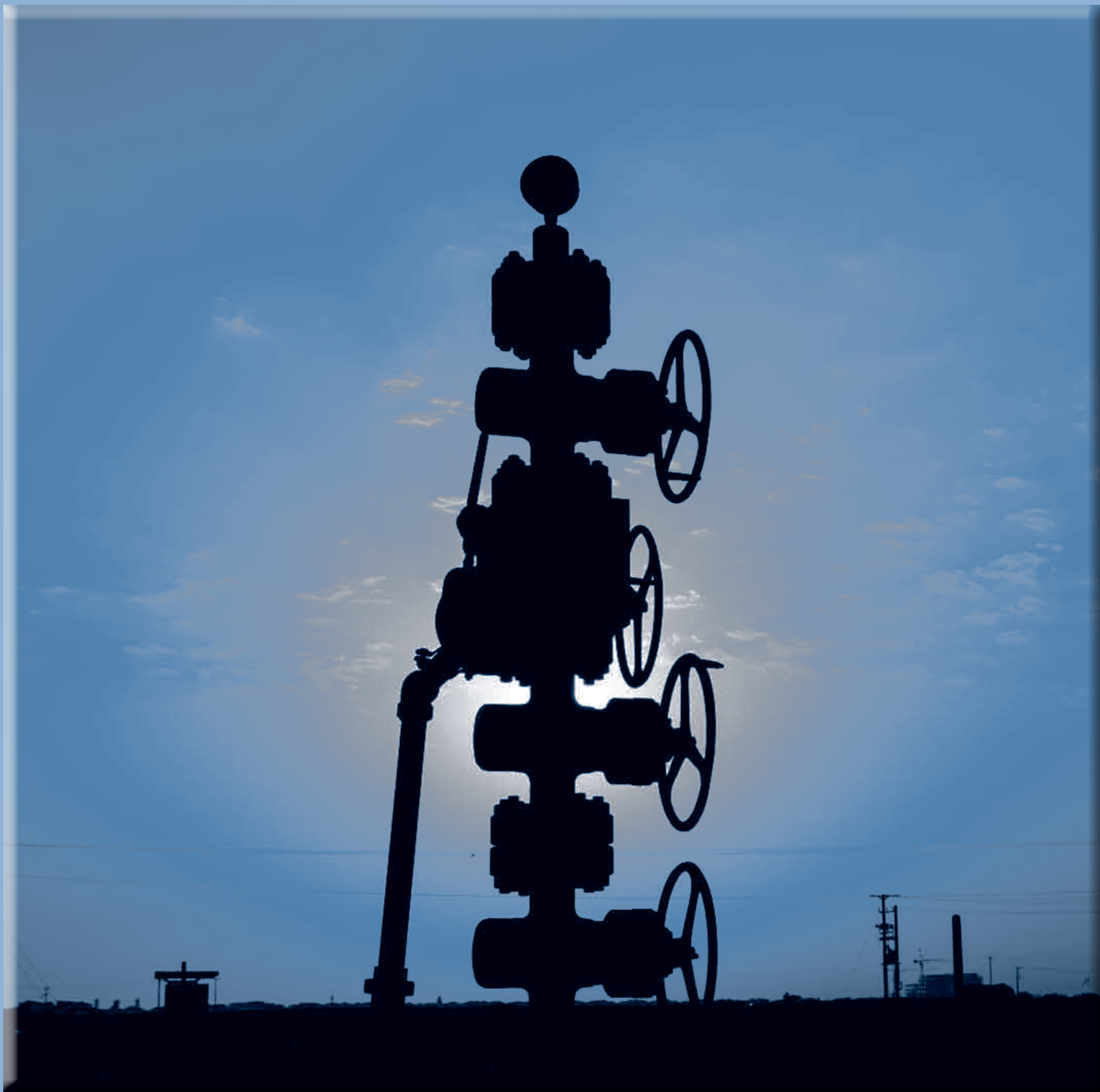
Hugoton Royalty Trust



2018

Annual Report and Form 10-K

Glossary of Terms

Bbl Barrel (of oil)

Bcf Billion cubic feet (of natural gas)

BOE Barrel of oil equivalent

Mcf Thousand cubic feet (of natural gas)

MMBtu One million British Thermal Units, a common energy measurement

net proceeds Gross proceeds received by XTO Energy from sale of production from the underlying properties, less applicable costs, as defined in the net profits interest conveyances.

net profits income Net proceeds multiplied by the net profits percentage of 80%, which is paid to the Trust by XTO Energy. "Net profits income" is referred to as "royalty income" for tax reporting purposes.

net profits interest An interest in an oil and gas property measured by net profits from the sale of production, rather than a specific portion of production. The following defined net profits interests were conveyed to the Trust from the underlying properties:

80% net profits interests – interests that entitle the Trust to receive 80% of the net proceeds from the underlying properties.

underlying properties XTO Energy's interest in certain oil and gas properties from which the net profits interests were conveyed. The underlying properties include working interests in predominantly gas-producing properties located in Kansas, Oklahoma and Wyoming.

working interest An operating interest in an oil and gas property that provides the owner a specified share of production that is subject to all production expense and development costs.

Selected Financial Data

Years Ended December 31,	2018	2017	2016	2015	2014
Net Profits Income	**$ 1,590,949**	$ 5,317,931	$ 2,617,640	$ 8,243,917	$ 44,446,473
Distributable Income	**370,040**	4,520,240	1,855,400	7,753,240	43,809,680
Distributable Income per Unit	**0.009251**	0.113006	0.046385	0.193831	1.095242
Distributions per Unit	**0.009251**	0.113006	0.046385	0.193831	1.095242
Total Assets at Year End	**16,945,147**	17,813,389	28,143,303	88,185,111	93,920,959

The Trust

Hugoton Royalty Trust was created on December 1, 1998 when XTO Energy Inc. conveyed 80% net profits interests in certain predominantly gas-producing properties located in Kansas, Oklahoma and Wyoming to the Trust. The net profits interests are the only assets of the Trust, other than cash held for Trust expenses and for distribution to unitholders.

Net profits income received by the Trust on the last business day of each month is calculated and paid by XTO Energy based on net proceeds received from the underlying properties in the prior month. Distributions, as calculated by the Trustee, are paid to month-end unitholders of record within ten business days.

Summary

The Trust was created to collect and distribute to unitholders monthly net profits income related to the 80% net profits interests. Such net profits income is calculated as 80% of the net proceeds received from certain working interests in predominantly gas-producing properties in Kansas, Oklahoma and Wyoming. Net proceeds from properties in each state are calculated by deducting production expense, development costs and overhead from revenues. If monthly costs exceed revenues from the underlying properties in any state, such excess costs must be recovered, with accrued interest, from future net proceeds of that state and cannot reduce net profits income from another state. Excess costs generally can occur during periods of higher development activity and/or lower gas prices. Underlying cumulative excess costs for the Kansas, Oklahoma and Wyoming conveyances remaining as of December 31, 2018 totaled $18.0 million ($14.4 million NPI), including accrued interest of $0.2 million ($0.1 million NPI). For further information on excess costs, see Note 4 to Financial Statements under Item 8, "Financial Statements and Supplementary Data" of the accompanying Form 10-K.

Cost Depletion is generally available to unitholders as a deduction from royalty income. Available depletion is dependent upon the unitholder's cost of units, purchase date and prior allowable depletion. It may be more beneficial for unitholders to deduct percentage depletion. Please see the 2018 tax booklet for specific instructions. Unitholders should consult their tax advisors for further information.

To Unitholders:

We are pleased to present the 2018 Annual Report on Form 10-K of the Hugoton Royalty Trust as filed with the Securities and Exchange Commission. This report contains important information about the Trust's net profits interests, including information provided to the Trustee by XTO Energy.

For the year ended December 31, 2018, net profits income totaled $1,590,949. After adding interest income of $23,152, net cash reserve activity of $128,157 and deducting Trust administration expense of $1,115,904, distributable income was $370,040 or $0.009251 per unit. Net profits income and distributions were 70% and 91.8%, respectively, lower than 2017 amounts primarily because of higher development costs, lower gas prices, lower oil and gas production, higher expenses, partially offset by excess costs and higher oil prices. For further information, see "Trustee's Discussion and Analysis of Financial Condition and Results of Operations" under Item 7 of the accompanying Form 10-K.

XTO Energy is a party to legal proceedings that may affect future Trust distributions. For further information, see Note 8 to Financial Statements under Item 8, "Financial Statements and Supplementary Data" of the accompanying Form 10-K.

Natural gas prices averaged $2.69 per Mcf for 2018, 8% lower compared to the 2017 average price of $2.92 per Mcf. The average 2018 oil price was $62.69 per Bbl, 35% higher compared to the 2017 average price of $46.47 per Bbl.

Gas sales volumes from the underlying properties for 2018 were 12,994,466 Mcf, or 35,601 Mcf per day, a decrease of 7% from 38,091 Mcf per day in 2017. Oil sales volumes from the underlying properties were 155,334 Bbls, or 426 Bbls per day in 2018, a decrease of 1% from 428 Bbls per day in 2017. For further information on sales volumes and product prices, see "Trustee's Discussion and Analysis of Financial Condition and Results of Operations" under Item 7 of the accompanying Form 10-K.

As of December 31, 2018, proved reserves for the underlying properties were estimated by independent engineers to be 121.2 Bcf of natural gas and 2.0 million Bbls of oil. From year-end 2017 to 2018, gas and oil reserves for the underlying properties increased 2% and 52%, respectively, primarily due to additions for new development activity and higher oil prices used to estimate reserves. Based on an allocation of these reserves, proved reserves attributable to the net profits interests were estimated to be 12.8 Bcf of natural gas and 443,000 Bbls of oil. Because Trust reserve quantities are determined using an allocation formula, any fluctuations in actual or assumed prices or costs will result in revisions to the estimated reserve quantities allocated to the net profits interests. All reserve information prepared by independent engineers has been provided to the Trustee by XTO Energy.

Estimated future net cash flows from proved reserves of the net profits interests at December 31, 2018 were $54.1 million. Using an annual discount factor of 10%, the present value of estimated future net cash flows at December 31, 2018 was $30.3 million. Proved reserve estimates and related future net cash flows have been determined based on a 12-month average gas price of $2.36 per Mcf and a 12-month average oil price of $63.30 per Bbl, based on the first-day-of-the-month price for each month in the period, and year end costs, including recovery of cumulative excess costs remaining at year end. Other guidelines used in estimating proved reserves, as prescribed by the Financial Accounting Standards Board, are described in Note 9 to Financial Statements

To Unitholders: Continued

under Item 8, "Financial Statements and Supplementary Data" of the accompanying Form 10-K. The present value of estimated future net cash flows is computed based on SEC guidelines and is not necessarily representative of the market value of Trust units.

As disclosed in the tax instructions provided to unitholders in February 2019, Trust distributions are considered portfolio income, rather than passive income. Unitholders should consult their tax advisors for further information.

Hugoton Royalty Trust
By: Simmons Bank, Trustee

By: Nancy Willis
Vice President

March 29, 2019

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2018

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ________ to ________.

Commission File No. 1-10476

Hugoton Royalty Trust
(Exact name of registrant as specified in its charter)

Texas	**58-6379215**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*

c/o Corporate Trustee:
Simmons Bank
2911 Turtle Creek Blvd, Suite 850

Dallas, Texas	**75219**
(Address of principal executive offices)	*(Zip Code)*

Registrant's telephone number, including area code
(at the office of the Corporate Trustee):
(855) 588-7839

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☑

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

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

Large accelerated filer ☐	Accelerated filer ☐
Non-accelerated filer ☑	Smaller reporting company ☑
	Emerging Growth Company ☐

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

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

The aggregate market value of units of beneficial interest held by non-affiliates of the registrant at June 30, 2018 (the last business day of the registrant's most recently completed second fiscal quarter) was approximately $26.0 million.

The number of units of beneficial interest outstanding as of February 15, 2019 was 40,000,000.

HUGOTON ROYALTY TRUST
2018 ANNUAL REPORT ON FORM 10-K

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HUGOTON ROYALTY TRUST

GLOSSARY OF TERMS

The following are definitions of significant terms used in this Annual Report on Form 10-K:

Bbl	Barrel (of oil)
Bcf	Billion cubic feet (of natural gas)
BOE	Barrel of oil equivalent
Mcf	Thousand cubic feet (of natural gas)
MMBtu	One million British Thermal Units, a common energy measurement
net proceeds	Gross proceeds received by XTO Energy from sale of production from the underlying properties, less applicable costs, as defined in the net profits interest conveyances.
net profits income	Net proceeds multiplied by the net profits percentage of 80%, which is paid to the Trust by XTO Energy. "Net profits income" is referred to as "royalty income" for tax reporting purposes.
net profits interest	An interest in an oil and gas property measured by net profits from the sale of production, rather than a specific portion of production. The following defined net profits interests were conveyed to the Trust from the underlying properties: *80% net profits interests* — interests that entitle the Trust to receive 80% of the net proceeds from the underlying properties.
underlying properties	XTO Energy's interest in certain oil and gas properties from which the net profits interests were conveyed. The underlying properties include working interests in predominantly gas-producing properties located in Kansas, Oklahoma and Wyoming.
working interest	An operating interest in an oil and gas property that provides the owner a specified share of production that is subject to all production expense and development costs.

PART I

Item 1. *Business*

Hugoton Royalty Trust (the "Trust") is an express trust created under the laws of Texas pursuant to the Hugoton Royalty Trust Indenture entered into on December 1, 1998 between XTO Energy Inc. (formerly known as Cross Timbers Oil Company), as grantor, and NationsBank, N.A., as Trustee. On January 9, 2014, the successor of NationsBank, N.A., U.S. Trust, Bank of America Private Wealth Management, a division of Bank of America, N.A., gave notice to unitholders that it would resign as Trustee. At a special meeting of the Trust's unitholders held on May 23, 2014, the unitholders of the Trust voted to approve the proposal to appoint Southwest Bank as successor Trustee of the Trust effective May 30, 2014.

Effective October 19, 2017, Simmons First National Corporation ("SFNC") completed its acquisition of First Texas BHC, Inc., the parent company of Southwest Bank, the Trustee of the Trust. SFNC is the parent of Simmons Bank. SFNC merged Southwest Bank with Simmons Bank effective February 20, 2018. Simmons Bank (the "Trustee") is now the Trustee of the Trust.

The principal office of the Trust is 2911 Turtle Creek Blvd, Suite 850, Dallas, Texas 75219. (Telephone number 855-588-7839). The Trust's internet web site is www.hgt-hugoton.com. We make available free of charge, through our web site, our Annual Report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934. These reports are accessible through our internet web site as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission. Information on our website is not incorporated into this report.

Effective December 1, 1998, XTO Energy conveyed to the Trust 80% net profits interests in certain predominantly natural gas producing working interest properties in Kansas, Oklahoma and Wyoming under three separate conveyances. In exchange for these net profits interest conveyances to the Trust, 40 million units of beneficial interest were issued to XTO Energy. In April and May 1999, XTO Energy sold a total of 17 million units in the Trust's initial public offering. In 1999 and 2000, XTO Energy also sold 1.3 million Trust units to certain of its officers. The Trust did not receive the proceeds from these sales of Trust units. In May 2006, XTO Energy distributed all of its remaining 21.7 million Trust units as a dividend to its common stockholders. XTO Energy currently is not a unitholder of the Trust. Units were listed and traded on the New York Stock Exchange under the symbol "HGT" until August 27, 2018, when the Trust units were delisted from the NYSE and began to be quoted on the OTCQX, which is maintained by the OTC Market Group Inc., under the symbol "HGTXU."

On June 25, 2010, XTO Energy became a wholly owned subsidiary of Exxon Mobil Corporation.

The net profits interests entitle the Trust to receive 80% of the net proceeds from the sale of oil and gas from the underlying properties. Each month XTO Energy determines the amount of cash received from the sale of production and deducts property and production taxes, production expense, development costs and overhead.

Net proceeds payable to the Trust depend upon production quantities, sales prices of oil and gas and costs to develop and produce oil and gas in the prior month. If monthly costs exceed revenues for any of the three conveyances (one for each of the states of Kansas, Oklahoma and Wyoming), such excess costs must be recovered, with accrued interest, from future net proceeds of that conveyance and cannot reduce net proceeds from other conveyances. For further information on excess costs, see Note 4 to Financial Statements under Item 8, Financial Statements and Supplementary Data.

The Trust is not liable for any production costs or liabilities attributable to the underlying properties. If at any time the Trust receives net profits income in excess of the amount due, the Trust is not obligated to return such overpayment, but future net profits income payable to the Trust will be reduced until the overpayment, plus interest at the prime rate, is recovered.

As a working interest owner, XTO Energy can generally decline participation in any operation and allow consenting parties to conduct such operations, as provided under the operating agreements. XTO Energy also can assign, sell, or otherwise transfer its interest in the underlying properties, subject to the net profits interests, or can abandon an underlying property if it is incapable of producing in paying quantities, as determined by XTO Energy.

To the extent allowed, XTO Energy is responsible for marketing its production from the underlying properties under existing sales contracts, or new arrangements on the best terms reasonably obtainable in the circumstances. See "Pricing and Sales Information" under Item 2, Properties.

Net profits income received by the Trust on or before the last business day of the month is related to net proceeds received by XTO Energy in the preceding month, and is generally attributable to oil and gas production two months prior. The amount to be distributed to unitholders each month by the Trustee is determined by:

Adding –

1. net profits income received;
2. interest income and any other cash receipts; and
3. cash available as a result of reduction of cash reserves; then

Subtracting –

1. liabilities paid; and
2. the reduction in cash available related to establishment of or increase in any cash reserve.

The monthly distribution amount is distributed to unitholders of record within ten business days after the monthly record date. The monthly record date is generally the last business day of the month. The Trustee calculates the monthly distribution amount and announces the distribution per unit at least ten days prior to the monthly record date.

The Trustee may establish cash reserves for contingencies. Cash held for such reserves, as well as for pending payment of the monthly distribution amount, may be invested in federal obligations or certificates of deposit of major banks.

The Trustee's function is to collect the net profits income from the net profits interests, to pay all Trust expenses, and to pay the monthly distribution amount to unitholders. The Trustee's powers are specified by the terms of the Trust indenture. The Trust cannot engage in any business activity or acquire any assets other than the net profits interests and specific short-term cash investments. The Trust has no employees since all administrative functions are performed by the Trustee.

Approximately 75% of the net profits income received by the Trust during 2018 was attributable to natural gas, as well as 64% of the Trust's estimated future net cash flows from proved reserves at December 31, 2018 (based on estimated future net cash flows using 12-month average oil and gas prices, based on the first-day-of-the-month price for each month in the period). There has historically been a greater demand for gas during the winter months than the rest of the year. Otherwise, Trust income generally is not subject to seasonal factors, nor dependent upon patents, licenses, franchises or concessions. The Trust conducts no research activities.

The oil and gas industry is highly competitive in all its phases. Operators of the properties in which the Trust holds interests encounter competition from other oil and gas companies and from individual producers and operators. Oil and natural gas are commodities, for which market prices are determined by external supply and demand factors. Current market conditions are not necessarily indicative of future conditions.

Item 1A. ***Risk Factors***

The following factors could cause actual results to differ materially from those contained in forward-looking statements made in this report and presented elsewhere by the Trustee from time to time. Such factors may have a material adverse effect upon the Trust's financial condition, distributable income and changes in trust corpus.

The following discussion of risk factors should be read in conjunction with the financial statements and related notes included under Item 8, Financial Statements and Supplementary Data. Because of these and other factors, past financial performance should not be considered an indication of future performance.

The Trust may not have sufficient cash to meet its obligations during the one year period after the date that the financial statements are issued and may choose or be required to take other actions to satisfy its obligations by seeking additional financing, which may not be successful.

Increases in excess costs for the Kansas, Oklahoma and Wyoming conveyances have resulted in no net proceeds to the Trust for the last nine months of 2018 and a reduction in the Trust's expense reserve. These conditions raise substantial doubt about the Trust's ability to continue as a going concern as the Trust may not have, based on the current estimated administrative expenses, sufficient cash to meet its obligations during the one year period after the date the financial statements are issued. The Trust's financial statements do not include any adjustments that might result from the outcome of this uncertainty. There are no assurances that the Trust will receive net profits income sufficient to pay its obligations during the one year period after the date the financial statements are issued, and as a result, may choose or be required to seek additional financing. If the Trust is unable to obtain additional financing and is unable to meet its obligations, the Trust could be forced to consider alternatives such as seeking approval from the unitholders to amend the Trust indenture either to permit the sale of some or all of the net profits interests or approve termination of the Trust. Unitholders could incur significant losses on their investment in the Trust or lose their entire investment in the Trust altogether if the funds obtained from any such sale or liquidation of the net profits interests are such that there are no funds to distribute to unitholders after all financial obligations are met. See Item 7 — Trustee's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources for more information.

The market price for the Trust units may not reflect the value of the net profits interests held by the Trust.

The public trading price for the Trust units tends to be tied to the recent and expected levels of cash distributions on the Trust units. The amounts available for distribution by the Trust vary in response to numerous factors outside the control of the Trust or XTO Energy, including prevailing prices for oil and natural gas produced from the underlying properties. The market price of the Trust units is not necessarily indicative of the value that the Trust would realize if the net profits interests were sold to a third party buyer. In addition, such market price is not necessarily reflective of the fact that, since the assets of the Trust are depleting assets, a portion of each cash distribution paid on the Trust units should be considered by investors as a return of capital, with the remainder being considered as a return on investment. There is no guarantee that distributions made to a unitholder over the life of these depleting assets will equal or exceed the purchase price paid by the unitholder.

Oil and natural gas prices fluctuate due to a number of uncontrollable factors, and any decline will adversely affect the net proceeds payable to the Trust and Trust distributions.

The Trust's monthly cash distributions are highly dependent upon the prices realized from the sale of natural gas and, to a lesser extent, oil. Oil and natural gas prices can fluctuate widely on a month-to-month basis in response to a variety of factors that are beyond the control of the Trust and XTO Energy. Factors that contribute to price fluctuations include instability in oil-producing regions, worldwide economic conditions, weather conditions, the supply of domestic and foreign oil, natural gas and natural gas liquids, consumer demand, the price and availability of alternative fuels, the proximity to, and capacity of, transportation facilities and the effect of worldwide energy conservation measures. Moreover, government regulations, such as regulation of natural gas transportation and price controls, can affect product prices. Oil and natural gas prices have declined substantially from historical highs and may not return to those levels in the foreseeable future, if ever. A significant decline in current oil or natural gas prices could have a material adverse effect on the amount of oil and natural gas that is economic to produce, Trust net profits (and therefore cash available for distribution to unitholders) and proved reserves attributable to the Trust's interests. The volatility of energy prices reduces the predictability of future cash distributions to Trust unitholders.

Higher production expense and/or development costs, without concurrent increases in revenue, will directly decrease the net proceeds payable to the Trust. Certain claimed production expenses by XTO Energy may reduce or eliminate distributions to unitholders for extended periods of time.

Production expense and development costs are deducted in the calculation of the Trust's share of net proceeds. Accordingly, higher or lower production expense and development costs, without concurrent changes in revenue, will directly decrease or increase the amount received by the Trust. If development costs and production expense for underlying properties in a particular state exceed the production proceeds from the properties (as was the case with respect to the properties underlying the Kansas net profits interest for all of 2017 and 2018 and with respect to the properties underlying the Wyoming net profits interests for the first three quarters of 2017, and all of 2018, and with respect to the properties underlying the Oklahoma net profits interest, the second, third, and fourth quarters of 2018 due to the drilling of four horizontal wells in Major County, Oklahoma), the Trust will not receive net profits income for those properties until future net proceeds from production in that state exceed the total of the excess costs plus accrued interest during the deficit period. Development activities may not generate sufficient additional revenue to repay the costs. Additionally, XTO Energy has advised the Trustee that total budgeted development costs for the underlying properties are between $2 million and $4 million for 2019 which could continue to exceed revenues for the underlying conveyance. See Item 2 — Properties.

As described in Note 8 — Contingencies to the Notes to Financial Statements, XTO Energy has advised the Trustee that it believes a portion of the settlement it has reached in the *Chieftain Royalty Company v. XTO Energy Inc.* class action lawsuit relates to the Trust. On July 27, 2018, plaintiffs submitted their final plan of allocation which was approved by the court on the same date. XTO Energy has advised the Trustee that it believes approximately $24.3 million in additional production costs should be allocated to the Trust. The Trustee has submitted a demand for arbitration and the arbitration panel has been selected. The hearing on the claims related to the *Chieftain* settlement has been scheduled for October 7, 2019. The remaining claims related to the computation of the Trust's net proceeds were bifurcated and will be heard at a later date, which is still to be determined. If the approximately $24.3 million allocated portion of the *Chieftain* settlement results in an adjustment to the Trust's share of net proceeds, it would result in additional excess costs under the Oklahoma conveyance that would likely result in no distributions under the Oklahoma conveyance for several years, or more depending on the results of operations of the underlying properties, while these additional excess costs are recovered. See Item 8 — Financial Statements and Supplementary Data — Notes to Financial Statements — Note 8 — Contingencies for additional information.

There may not be an active market for the Trust units.

On August 27, 2018, the Trust units were delisted from the NYSE and began to be quoted on the OTCQX, which is maintained by the OTC Market Group Inc., under the symbol "HGTXU." Trading on the OTCQX is often characterized as thin with sporadic fluctuations in price and the availability of buyers or sellers of a security. No assurance can be given that an active trading market for our Trust units will further develop or continue. The Trust units will likely be subject to greater volatility and lower trading volumes than when the Trust units were listed on the New York Stock Exchange. This could depress the trading price of the Trust units and make it more difficult to purchase, dispose of or obtain accurate quotations as to the value of the Trust units. We currently expect the Trust units will continue to trade on the OTCQX.

Proved reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions could cause the quantities and net present value of the reserves to be overstated.

Estimating proved oil and gas reserves is inherently uncertain. Petroleum engineers consider many factors and make assumptions in estimating reserves and future net cash flows. Those factors and assumptions include historical production from the area compared with production rates from similar producing areas, the effects of governmental regulation, assumptions about future commodity prices, production expense and development costs, taxes and capital expenditures, the availability of enhanced recovery techniques and relationships with landowners, working interest partners, pipeline companies and others. Lower oil and gas prices generally cause lower estimates of proved reserves. Ultimately, actual production, revenues and expenditures for the underlying properties will vary from estimates and those variances could be material. Because the Trust owns net profits interests, it does not own a specific percentage of the oil and gas reserves. Estimated proved reserves for the net profits interests are based on estimates of reserves for the underlying properties and an allocation method that considers estimated future net proceeds and oil and gas prices. Because Trust reserve quantities are determined using an allocation formula, increases or decreases in oil and gas prices can significantly affect estimated reserves of the net profits interests.

Operational risks and hazards associated with the development and operations of the underlying properties may decrease Trust distributions.

There are operational risks and hazards associated with the production and transportation of oil and natural gas, including without limitation natural disasters, blowouts, explosions, fires, leakage of oil or natural gas, releases of other hazardous materials, mechanical failures, cratering, and pollution. Any of these or similar occurrences could result in the interruption or cessation of operations, personal injury or loss of life, property damage, damage to productive formations or equipment, damage to the environment or natural resources, or cleanup obligations. The operation of oil and gas properties is also subject to various laws and regulations. Non-compliance with such laws and regulations could subject the operator to additional costs, sanctions or liabilities. The uninsured costs resulting from any of the above or similar occurrences could be deducted as a production expense or development cost in calculating the net proceeds payable to the Trust, and would therefore reduce Trust distributions by the amount of such uninsured costs.

Future net profits may be subject to risks relating to the creditworthiness of third parties.

The Trust does not lend money and has limited ability to borrow money, which the Trustee believes limits the Trust's risk from exposure to credit markets. The Trust's future net profits, however, may be subject to risks relating to the creditworthiness of the operators of the underlying properties and other purchasers of crude oil and natural gas produced from the underlying properties. This creditworthiness may be impacted by the price of crude oil and natural gas.

Trust unitholders and the Trustee have no influence over the operations on, or future development of, the underlying properties.

Neither the Trustee nor the Trust unitholders can influence or control the operation or future development of the underlying properties. The failure of an operator to conduct its operations or discharge its obligations in a proper manner could have an adverse effect on the net proceeds payable to the Trust. Although XTO Energy and other operators of the underlying properties must adhere to the standard of a prudent operator, they are under no obligation to continue operating the properties. Neither the Trustee nor Trust unitholders have the right to replace an operator.

The assets of the Trust represent interests in depleting assets and, if XTO Energy or any other operators developing the underlying properties do not perform additional successful development projects, the assets may deplete faster than expected. Eventually, the assets of the Trust will cease to produce in commercial quantities and the Trust will cease to receive proceeds from such assets.

The net proceeds payable to the Trust are derived from the sale of hydrocarbons from depleting assets. Future maintenance and development projects on the underlying properties will affect the quantity of proved reserves and can offset the reduction in the depletion of proved reserves. The timing and size of these projects will depend on the market prices of oil and natural gas. If the operator(s) of the properties do not implement additional maintenance and development projects, the future rate of production decline of proved reserves may be higher than the rate currently expected by the Trust. Because the net proceeds payable to the Trust are derived from the sale of hydrocarbons from depleting assets, the portion of distributions to unitholders attributable to depletion may be considered a return on capital as opposed to a return on investment. Distributions that are a return of capital will ultimately diminish the depletion tax benefits available to the unitholders, which could reduce the market value of the units over time. Eventually, the properties underlying the Trust’s net profits interest will cease to produce in commercial quantities and the Trust will, therefore, cease to receive any net proceeds therefrom.

XTO Energy drilled four horizontal wells in Major County, Oklahoma during 2018 which are currently expected to be completed and begin producing during 2019. There is no guarantee that these wells will produce or produce in commercial quantities sufficient to recoup the investment.

Terrorism and geopolitical hostilities could adversely affect Trust distributions or the market price of the Trust units.

Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign, as well as military or other actions taken in response, cause instability in the global financial and energy markets. Terrorism and other geopolitical hostilities could adversely affect Trust distributions or the market price of the Trust units in unpredictable ways, including through the disruption of fuel supplies and markets, increased volatility in oil and natural gas prices, or the possibility that the infrastructure on which the operators of the underlying properties rely could be a direct target or an indirect casualty of an act of terror.

XTO Energy may transfer its interest in the underlying properties without the consent of the Trust or the Trust unitholders.

XTO Energy may at any time transfer all or part of its interest in the underlying properties to another party. Neither the Trust nor the Trust unitholders are entitled to vote on any transfer of the properties underlying the Trust’s net profits interests, and the Trust will not receive any proceeds of any such transfer. Following any transfer, the transferred property will continue to be subject to the net profits interests of the Trust, but the calculation, reporting and remitting of net proceeds to the Trust will be the responsibility of the transferee.

XTO Energy or any other operator of any underlying property may abandon the property, thereby terminating the related net profits interest payable to the Trust.

XTO Energy or any other operator of the underlying properties, or any transferee thereof, may abandon any well or property without the consent of the Trust or the Trust unitholders if they reasonably believe that the well or property can no longer produce in commercially economic quantities. This could result in the termination of the net profits interest relating to the abandoned well or property.

The net profits interests can be sold and the Trust would be terminated. The Trust will also be terminated if it fails to generate sufficient gross proceeds.

The Trust may sell the net profits interests if the holders of 80% or more of the outstanding Trust units approve the sale or vote to terminate the Trust. The Trust will terminate if it fails to generate gross proceeds from the underlying properties of at least $1,000,000 per year over any successive two-year period. Sale of all of the net profits interests will terminate the Trust. The net proceeds of any sale must be for cash with the proceeds less administrative costs promptly distributed to the Trust unitholders.

The sale of the remaining net profits interests and the termination of the Trust will be taxable events to the Trust unitholders. Generally, a Trust unitholder will realize gain or loss equal to the difference between the amount realized on the sale and termination of the Trust and his adjusted basis in such units. Gain or loss realized by a Trust unitholder who is not a dealer with respect to such units and who has a holding period for the units of more than one year will be treated as long-term capital gain or loss except to the extent of any depletion recapture amount, which must be treated as ordinary income. Other federal and state tax issues concerning the Trust are discussed under Item 2 and Note 6 to the Trust's financial statements, which are included herein. Each Trust unitholder should consult his own tax advisor regarding Trust tax compliance matters, including federal and state tax implications concerning the sale of the net profits interests and the termination of the Trust.

Trust unitholders have limited voting rights and have limited ability to enforce the Trust's rights against XTO Energy or any other operator of the underlying properties.

The voting rights of a Trust unitholder are more limited than those of stockholders of most public corporations. For example, there is no requirement for annual meetings of Trust unitholders or for an annual or other periodic re-election of the Trustee. Additionally, Trust unitholders have no voting rights in XTO Energy or Exxon Mobil Corporation.

The Trust indenture and related trust law permit the Trustee and the Trust to sue XTO Energy or any other operator of the underlying properties to compel them to fulfill the terms of the conveyance of the net profits interests. If the Trustee does not take appropriate action to enforce provisions of the conveyance, the recourse of the Trust unitholders would likely be limited to bringing a lawsuit against the Trustee to compel the Trustee to take specified actions. Trust unitholders probably would not be able to sue XTO Energy or any other operator of the underlying properties.

Financial information of the Trust is not prepared in accordance with U.S. GAAP.

The financial statements of the Trust are prepared on a modified cash basis of accounting, which is a comprehensive basis of accounting other than U.S. generally accepted accounting principles, or U.S. GAAP. Although this basis of accounting is permitted for royalty trusts by the Securities and Exchange Commission, the financial statements of the Trust differ from U.S. GAAP financial statements because net profits income is not accrued in the month of production, expenses are not recognized when incurred and cash reserves may be established for certain contingencies that would not be recorded in U.S. GAAP financial statements. See Item 8 — Financial Statements and Supplementary Data — Notes to Financial Statements — Note 2 Basis of Accounting and Note 5 Development Costs for additional information.

The limited liability of Trust unitholders is uncertain.

The Trust unitholders are not protected from the liabilities of the Trust to the same extent that a shareholder would be protected from a corporation's liabilities. The structure of the Trust does not include the interposition of a limited liability entity such as a corporation or limited partnership which would provide further limited liability protection to Trust unitholders. While the Trustee is liable for any excess liabilities incurred if the Trustee fails to ensure that such liabilities are to be satisfied only out of Trust assets, under the laws of Texas, which are unsettled on this point, a unitholder may be jointly and severally liable for any liability of the Trust if the satisfaction of such liability was not contractually limited to the assets of the Trust and the assets of the Trust and the Trustee are not adequate to satisfy such liability. As a result, Trust unitholders may be exposed to personal liability. The Trust, however, is not liable for production costs or other liabilities of the underlying properties.

Drilling oil and natural gas wells is a high-risk activity and subjects the Trust to a variety of factors that it cannot control.

Drilling oil and natural gas wells involves numerous risks, including the risk that commercially productive oil and natural gas reservoirs are not encountered. The presence of unanticipated pressures or irregularities in formations, miscalculations or accidents may cause drilling activities to be unsuccessful. In addition, there is often uncertainty as to the future cost or timing of drilling, completing and operating wells. Further, development activities may be curtailed, delayed or canceled as a result of a variety of factors, including:

1. reduced oil or natural gas prices;
2. unexpected drilling conditions;
3. title problems;
4. restricted access to land for drilling or laying pipeline;
5. pressure or irregularities in formations;
6. equipment failures or accidents;
7. adverse weather conditions or natural disasters; and
8. costs of, or shortages or delays in the availability of, drilling rigs, tubular materials and equipment.

While these risks do not expose the Trust to liabilities of the drilling contractor or operator of the well, they can reduce net proceeds payable to the Trust and Trust distributions by decreasing oil and gas revenues or increasing production expense or development costs from the underlying properties. Furthermore, these risks may cause the costs of development activities on the underlying properties to exceed the revenues therefrom, thereby reducing net proceeds payable to the Trust and Trust distributions.

The underlying properties are subject to complex federal, state and local laws and regulations that could adversely affect net proceeds payable to the Trust and Trust distributions.

Extensive federal, state and local regulation of the oil and natural gas industry significantly affects operations on the underlying properties. In particular, oil and natural gas development and production are subject to stringent environmental regulations. These regulations have increased the costs of planning, designing, drilling, installing, operating and abandoning oil and natural gas wells and other related facilities, which costs could reduce net proceeds payable to the Trust and Trust distributions. These regulations may become more demanding in the future. See Item 2 — Properties — Regulation, and Item 7 — Trustee's Discussion and Analysis of Financial Condition and Results of Operations — Greenhouse Gas Emissions and Climate Change Regulations.

Cash held by the Trustee is not insured by the Federal Deposit Insurance Corporation.

Currently, cash held by the Trust reserved for the payment of accrued liabilities and estimated future expenses and distributions to unitholders is typically held in a treasury fund that under normal market conditions invests exclusively in U.S. Treasury obligations. Although the fund's underlying investments are obligations of the U.S. government, the fund itself is not insured by the Federal Deposit Insurance Corporation. In the event that the fund becomes insolvent, the Trustee may be unable to recover any or all such cash from the insolvent fund. Any loss of such cash may have a material adverse effect on the Trust's cash balances and any distributions to unitholders.

The tax treatment of an investment in Trust units could be affected by recent and potential legislative changes, possibly on a retroactive basis.

U.S. federal tax reform legislation informally known as the Tax Cuts and Jobs Act (the "TCJA") was enacted December 22, 2017, and makes significant changes to the federal income tax rules applicable to both individuals and entities, including changes to the effective tax rate on a Trust unitholder's allocable share of certain income from the Trust. The TCJA is complex and lacks administrative guidance, thus, Trust unitholders should consult their tax advisor regarding the TCJA and its effect on an investment in Trust units.

For taxable years beginning after 2017, the highest marginal U.S. federal income tax rates applicable to ordinary income and long-term capital gains of individuals are 37% and 20%, respectively. Any modification to the U.S. federal income tax laws or interpretations thereof (including administrative guidance relating to the TCJA) may be applied retroactively and could adversely affect our business, financial condition or results of operations. The Trust is unable to predict whether any changes or other proposals will ultimately be enacted, or whether any adverse interpretations will be used. Any such changes or interpretations could negatively impact the value of an investment in the Trust units.

Item 1B. *Unresolved Staff Comments*

As of December 31, 2018, the Trust did not have any unresolved Securities and Exchange Commission staff comments.

Item 2. *Properties*

The net profits interests are the principal asset of the Trust. The Trustee cannot acquire any other assets, with the exception of certain short-term investments as specified under Item 1, Business. The Trustee may sell or otherwise dispose of all or any part of the net profits interests if approved by a vote of holders of 80% or more of the outstanding Trust units, or upon termination of the Trust. Otherwise, the Trust is required to sell up to 1% of the value of the net profits interests in any calendar year, pursuant to notice from XTO Energy of its desire to sell the related underlying properties. Any sale must be for cash with 80% of the proceeds distributed to the unitholders on the next declared distribution. All the underlying properties are currently owned by XTO Energy. XTO Energy may sell all or any portion of the underlying properties at any time, subject to and burdened by the net profits interests.

The underlying properties are predominantly gas-producing properties with established production histories in the Hugoton area of Oklahoma and Kansas, the Anadarko Basin of Oklahoma and the Green River Basin of Wyoming. The average reserve-to-production index for the underlying properties as of December 31, 2018 is approximately 11 years. This index is calculated using total proved reserves and estimated 2019 production for the underlying properties. The projected 2019 production is from proved developed producing reserves as of December 31, 2018. Based on estimated future net cash flows at 12-month average oil and gas prices, based on the first-day-of-the-month price for each month in the period, the future net cash flows from proved reserves of the underlying properties are approximately 64% natural gas and 36% oil. XTO Energy operates approximately 95% of the underlying properties.

Because the underlying properties are working interests, production expense, development costs and overhead are deducted in calculating net profits income. As a result, net profits income is affected by the level of maintenance and development activity on the underlying properties. See Trustee's Discussion and Analysis of Financial Condition and Results of Operations, under Item 7. Total 2018 development costs deducted for the underlying properties were $21.8 million, an increase of 679% from the prior year. XTO Energy has informed the Trustee that total 2019 budgeted development costs for the underlying properties are between $2 million and $4 million. Changes in oil or natural gas prices could impact future development plans on the underlying properties.

XTO Energy has advised the Trustee that, effective April 1, 2017, Cross Timbers Energy Services, Inc. ("CTES"), a wholly owned marketing subsidiary of XTO Energy, has assigned all gas sales contracts for production from the underlying properties to XTO Energy. XTO Energy will directly market and sell the gas to third parties. XTO Energy has advised the Trustee that there are no changes to the terms of the contracts related to the assignment and no impact on Trust distributions.

Significant Properties

Hugoton Area

Natural gas was discovered in the Hugoton area in 1922. With an estimated five million productive acres covering parts of Texas, Oklahoma and Kansas, the Hugoton area is one of the largest domestic natural gas producing areas. During 2018, daily sales volumes from the underlying properties in the Hugoton area averaged approximately 9,700 Mcf of gas and 41 Bbls of oil.

Most of the production from the underlying properties in the Hugoton area is from the Chase formation. XTO Energy has informed the Trustee that it has begun to develop other formations that underlie the 79,500 net acres held by production by the Chase formation wells, which include the Council Grove, Morrow, Chester and St. Louis formations. These formations are characterized by both oil and gas production from a variety of structural and stratigraphic traps. Prior to 2011, XTO Energy drilled wells to these formations and plans to continue this development program sometime in the future.

Within this area, XTO Energy did not drill any wells but did perform 3 workovers in 2018. XTO Energy has informed the Trustee that it does not plan to drill any new wells but may perform up to 5 workovers during 2019.

XTO Energy's future development plans for the underlying properties in the Hugoton area include:

1. additional compression to lower line pressures;
2. installing artificial lift;
3. opening new producing zones in existing wells;
4. restimulating producing intervals in existing wells utilizing new technology;
5. deepening existing wells to new producing zones; and
6. future drilling of additional wells.

Effective May 1, 2014, XTO Energy entered into a gas sales and processing contract with DCP Midstream, L.P. to process all gas production from its wells attached to the Timberland Gathering System in Seward County, Kansas and in Texas and Beaver Counties, Oklahoma. The system collects the majority of its throughput from underlying properties, which XTO Energy has advised the Trustee has been approximately 9,100 Mcf per day. XTO Energy receives 100% of the net value for residue gas based upon a price per MMBtu of Panhandle Eastern Pipe Line Company index. Under this contract DCP is entitled to charge a processing fee of $0.25 per Delivery Point MMBtu and a helium processing fee of $0.05 per 97% Delivery Point Mcf in addition to other deductions such as for fuel and transportation. XTO Energy has exercised its contractual right to take in kind and sell its NGLs and helium. XTO Energy sells 100% of the net value for any recovered NGLs to ONEOK at Conway pricing as posted by Oil Price Information Services minus an adjusted base differential. XTO Energy sells the helium to Air Products and Chemicals, Inc. and Air Products Helium, Inc. under a pricing formula based upon the open market crude helium sales price established by the U.S. Bureau of Land Management. Timberland Gathering & Processing Company, Inc. ("Timberland"), an affiliate of XTO Energy, provides gathering from the wellhead to DCP's gathering system for a fee of $0.75 per Mcf of gas delivered by XTO Energy. The sales contract with DCP Midstream, L.P. is in force from May 1, 2014 until March 31, 2019, and from year to year thereafter until canceled by either party upon 180 days written notice.

Other Hugoton gas production is sold under a third party contract that remains in effect for the life of the lease. Under the contract, XTO Energy receives 74.5% of the net proceeds received by the buyer from the sale of the residue gas and liquids produced from certain underlying properties. The residue gas net proceeds are based upon the weighted average price of the gas sold by the buyer at its facilities, and the liquids net proceeds are based upon an average daily index sales price, less transportation, processing and storage fees incurred by the buyer. The buyer agrees to use its best efforts to take all of the gas produced, subject to its market requirements. The buyer has been taking all of the gas produced for over ten years.

Anadarko Basin

Oil and gas accumulations were discovered in the Anadarko Basin of western Oklahoma in 1945. XTO Energy is one of the largest producers in the Ringwood, Northwest Okeene and Cheyenne Valley fields of Major County, the Northeast Cedardale field of Woodward County and the Elk City field of Beckham County, the principal producing regions of the underlying properties in the Anadarko Basin. Daily sales volumes from the underlying properties in the Anadarko Basin averaged 15,100 Mcf of gas and 364 Bbls of oil in 2018.

The fields in the Major County area are characterized by oil and gas production from a variety of structural and stratigraphic traps. Productive zones include the Oswego, Red Fork, Inola, Chester, Manning, Mississippian, Hunton and Arbuckle formations. Within this area, XTO Energy drilled 4 wells and performed 32 workovers in 2018. XTO Energy has informed the Trustee that it plans to complete the four new horizontal wells in the first half of 2019 and may perform up to 30 workovers in Major County during 2019.

The fields within Woodward County are characterized primarily by gas production from a variety of structural and stratigraphic traps. Productive zones include the Cottage Grove, Oswego, Chester and Mississippian formations. Within this area, XTO Energy did not drill any wells but did perform 10 workovers in 2018. XTO Energy has informed the Trustee that it does not plan to drill any new wells but may perform up to 10 workovers in Woodward County during 2019.

The Elk City field on the eastern edge of Beckham County produces oil and gas from a structural anticline with stratigraphic trapping features. Production zones include the Hoxbar, Atoka and Morrow formations. Within this area, XTO Energy did not drill any wells but did perform 5 workovers in 2018. XTO Energy has informed the Trustee that it does not plan to drill any new wells but may perform up to 10 workovers within the Elk City field during 2019.

XTO Energy plans to further develop the underlying properties in the Anadarko Basin primarily through:

1. mechanical stimulation of existing wells;
2. installing artificial lift;
3. opening new producing zones in existing wells;
4. deepening existing wells to new producing zones; and
5. future drilling of additional wells.

A gathering subsidiary of XTO Energy operates a 300-mile gathering system and pipeline in the Major County area. The gathering subsidiary and a third-party processor purchase natural gas produced at the wellhead from XTO Energy and other producers in the area under various agreements, most of which were entered into in the 1960’s and 1970’s, and which include life-of-production terms such that the contracts will continue until there is no further production from the underlying properties, unless the production declines so that it is no longer economical to take the gas. The gathering subsidiary and the third-party processor are required to take certain minimum volumes of the gas produced but have been taking all of the volumes produced for over ten years. The gathering subsidiary gathers and transports the gas to a third-party processor, which processes the gas and pays XTO Energy and other producers for at least 50% of the liquids processed based upon a weighted average sales price less transportation charges, which price may vary in the event of inadequate markets. After the gas is processed, the gathering subsidiary transports the gas via a residue pipeline to a connection with an interstate pipeline. The gathering subsidiary pays XTO Energy for the residue gas based upon a weighted average price from downstream sales to third parties, which price will vary monthly based upon market conditions. The gathering subsidiary pays this price to XTO Energy less a compression and gathering fee of approximately $0.31 per Mcf of residue gas. This gathering fee was previously approved by the Federal Energy Regulatory Commission when the gathering subsidiary was regulated. During 2018, the gathering system collected approximately 6,100 Mcf per day, approximately 50% of which XTO Energy operates. Estimated capacity of the gathering system is 24,000 Mcf per day. The gathering subsidiary also provides contract operating services to properties in Woodward County, collecting approximately 2,900 Mcf per day, for an average fee of approximately $0.11 per Mcf. The fee is subject to an annual price renegotiation under which either party can request that the price provided under the contract be renegotiated. The contract continues on a yearly basis, and it is subject to termination upon written notice prior to its annual renewal or in the event the parties fail to agree upon a pricing renegotiation. XTO Energy also sells gas directly to third parties. The price paid to XTO Energy is based upon the weighted average price of several published indices, which price varies upon market conditions, and includes a deduction for any transportation fees charged by the third party. Neither party has a firm obligation to sell or purchase any specific minimum quantity of gas.

Green River Basin

The Green River Basin is located in southwestern Wyoming. Natural gas was discovered in the Fontenelle field of the Green River Basin in the early 1970's. The producing reservoirs are the Frontier, Baxter and Dakota sandstones.

Daily 2018 sales volumes from the underlying properties in the Fontenelle field averaged 10,800 Mcf of natural gas and 21 Bbls of oil. XTO Energy did not drill any wells or perform any workovers in the Green River Basin in 2018. XTO Energy has advised the Trustee that it does not plan to drill any new wells or perform any workovers in the Green River Basin during 2019. XTO Energy has advised the Trustee that it is continuing its efforts to reduce pipeline pressure which has shown potential for increasing production and extending field life in the Fontenelle field. XTO Energy has advised the Trustee that a salt water disposal conversion may be executed in 2019 to assist with disposal in the Fontenelle field.

Potential development activities for the underlying properties in this area include:

1. installing artificial lift;
2. restimulating producing intervals utilizing new technology;
3. additional compression to lower line pressures; and
4. opening new producing zones in existing wells.

XTO Energy markets the gas produced from the Fontenelle field and nearby properties under various marketing arrangements. Under the agreement covering the majority of the gas sold, XTO Energy compresses the gas on the lease, transports it off the lease and compresses the gas again prior to entry into the gas plant pipeline. The pipeline transports the gas to the gas plant, where the gas is processed, then redelivered to XTO Energy. The owner of the gas plant and related pipeline charges XTO Energy for operational fuel and processing and has agreed to accept certain volumes, which amounts can be adjusted by the owner. The owner may be able to cease taking volumes if it has valid unaddressed concerns regarding the creditworthiness of XTO Energy. In 2018, the fuel charge was approximately 1% of the volumes produced and the fee was approximately $0.12 per MMBtu. These charges are adjusted annually based upon a published governmental economic index, and the contract renews on a year-to-year basis. XTO Energy transports and sells this gas directly to the markets based on a spot sales price on a month-to-month term, and the volumes to be sold are generally determined upon a monthly basis. These contracts may be terminated by either party if there are credit issues with the other party. The gas not sold under the above arrangement may be gathered and sold under a similar arrangement on a month-to-month term where the fee is approximately $0.20 per MMBtu and is adjusted annually. The amount of gas that the gatherer is required to gather is limited to certain maximum volumes, and the gatherer may be able to cease taking volumes if it has valid unaddressed concerns regarding the creditworthiness of XTO Energy. Alternatively, the gas may be sold under a contract where XTO Energy directly sells the gas to a third party on the lease at an adjusted index price, which price varies upon market conditions. The contract continues on a month-to-month basis, and the buyer is obligated to make a good faith effort to purchase a minimum 90% of the gas nominated by buyer for purchase. Condensate is sold to an independent third party at market rates on a month-to-month basis. The purchaser accepts all condensate delivered at the lease, but either party may suspend performance of the contract if there are credit issues with the other party.

Producing Acreage, Drilling and Well Counts

For the following data, "gross" refers to the total wells or acres on the underlying properties in which XTO Energy owns a working interest and "net" refers to gross wells or acres multiplied by the percentage working interest owned by XTO Energy. Although many of XTO Energy's wells produce both oil and gas, a well is categorized as an oil well or a gas well based upon the ratio of oil to natural gas production. Operated wells are managed by XTO Energy, while non-operated wells are managed by others.

The underlying properties are interests in developed properties located primarily in gas producing regions of Kansas, Oklahoma and Wyoming. The following is a summary of the approximate producing acreage of the underlying properties at December 31, 2018. Undeveloped acreage is not significant.

	Gross	Net
Hugoton Area	203,154	191,091
Anadarko Basin	157,648	122,535
Green River Basin	32,194	25,541
Total	392,996	339,167

The following is a summary of the producing wells on the underlying properties as of December 31, 2018:

	Operated Wells		Non-operated Wells		Total(a)	
	Gross	Net	Gross	Net	Gross	Net
Gas	1,103.0	985.3	248.0	53.4	1,351.0	1,038.7
Oil	42.0	39.0	6.0	0.8	48.0	39.8
Total	1,145.0	1,024.3	254.0	54.2	1,399.0	1,078.5

(a) During 2018, 2017 and 2016 there were no exploratory or dry wells drilled on the underlying properties. There were 2 gross (0.11 net), 1 gross (0.0 net) and zero gross developmental wells drilled in 2018, 2017 and 2016, respectively. Not included in the totals are 4 gross (2.83 net) operated wells and 2 gross (0.20 net) non-operated wells in process of drilling at December 31, 2018.

Estimated Proved Reserves and Future Net Cash Flows

The following are proved reserves of the underlying properties, as estimated by independent engineers, and proved reserves and future net cash flows from proved reserves of the net profits interests, based on an allocation of these reserves, at December 31, 2018:

	Underlying Properties		Net Profits Interests			
	Proved Reserves[(a)]		Proved Reserves[(a)(b)]		Future Net Cash Flows from Proved Reserves[(a)(c)]	
(in thousands)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Undiscounted	Discounted
Oklahoma	87,208	1,896	12,035	437	$52,296	$29,350
Wyoming	26,219	41	59	—	130	99
Kansas	7,763	68	696	6	1,686	842
TOTAL	121,190	2,005	12,790	443	$54,112	$30,291

(a) Based on 12-month average oil price of $63.30 per Bbl and $2.36 per Mcf for gas, based on the first-day-of-the-month price for each month in the period.

(b) Since the Trust has defined net profits interests, the Trust does not own a specific percentage of the oil and gas reserves. Oil and gas reserves are allocated to the net profits interests by dividing Trust net cash inflows by 12-month average oil and gas prices. As such, reserves allocated to the Trust have been reduced to reflect recovery of the Trust's portion of applicable production and development costs, which includes overhead and excess costs. Any conveyance where costs exceed revenues will result in zero allocated net profits interests reserves for that conveyance.

(c) Before income taxes, since future net cash flows are not subject to taxation at the trust level. Future net cash flows are discounted at an annual rate of 10%.

Proved reserves at December 31, 2018 consist of the following:

	Underlying Properties		Net Profits Interests	
	Proved Reserves		Proved Reserves	
(in thousands)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)
Proved developed reserves	110,953	1,339	7,944	121
Proved undeveloped reserves	9,956	666	4,811	322
Proved non-producing reserves	281	—	35	—
Total proved reserves	121,190	2,005	12,790	443

Approximately 90% of the underlying proved reserves are proved developed reserves.

The process of estimating oil and gas reserves is complex and requires significant judgment as discussed in Item 1A, Risk Factors, and is performed by XTO Energy. As a result, XTO Energy has developed internal policies and controls for estimating and recording reserves. XTO Energy's policies regarding booking reserves require proved reserves to be in compliance with the SEC definitions and guidance. XTO Energy's policies assign responsibilities for compliance in reserves bookings to its reserve engineering group and require that reserve estimates be made by qualified reserves estimators, as defined by the Society of Petroleum Engineers' standards. All qualified reserves estimators are required to receive education covering the fundamentals of SEC proved reserves assignments.

The XTO Energy reserve engineering group reviews reserve estimates with third-party petroleum consultants, Miller and Lents, Ltd., independent petroleum engineers. Miller and Lents, Ltd. estimated oil and gas reserves attributable to the underlying properties as of December 31, 2018, 2017, 2016 and 2015. Miller and Lents' primary technical person responsible for calculating the Trust's reserves has more than ten years of experience as a reserve engineer. The estimated reserves for the underlying properties are then used by XTO Energy to calculate the estimated oil and gas reserves attributable to the net profits interests. Numerous uncertainties are inherent in estimating reserve volumes and values, and such estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of these reserves may be substantially different from the original estimates.

Reserve quantities and revenues for the net profits interests were estimated from projections of reserves and revenues attributable to the underlying properties. Since the Trust has defined net profits interests, the Trust does not own a specific percentage of the oil and gas reserves. Oil and gas reserves are allocated to the net profits interests by dividing Trust net cash inflows by 12-month average oil and gas prices.

Oil and Natural Gas Production

Trust production is recognized in the period net profits income is received, which is the month following receipt by XTO Energy, and generally two months after the time of production. Oil and gas sales volumes are allocated to the net profits interests based upon a formula that considers oil and gas prices and the total amount of production expense and development costs. As such, the underlying property production volume changes may not correlate with the Trust's net profit share of those volumes in any given period.

Oil and gas production and average sales prices attributable to the underlying properties and the net profits interests for each of the two years ended December 31 were as follows:

	2018	2017
Production		
Underlying Properties		
Gas – Sales (Mcf)	**12,994,466**	13,903,368
Average per day (Mcf)	**35,601**	38,091
Oil – Sales (Bbls)	**155,334**	156,352
Average per day (Bbls)	**426**	428
Net Profits Interests		
Gas – Sales (Mcf)	**447,961**	1,628,427
Average per day (Mcf)	**1,227**	4,461
Oil – Sales (Bbls)	**7,627**	26,775
Average per day (Bbls)	**21**	73
Average Sales Price		
Gas (per Mcf)	**$ 2.69**	$ 2.92
Oil (per Bbl)	**$ 62.69**	$ 46.47
Average Production Cost per BOE	**$12.83**	$ 11.60

Oil and gas production by conveyance attributable to the underlying properties for each of the two years ended December 31 were as follows:

Conveyance	Underlying Gas Production (Mcf) 2018	2017
Kansas	**1,077,152**	1,225,165
Oklahoma	**7,988,035**	8,584,930
Wyoming	**3,929,279**	4,093,273
Total	**12,994,466**	13,903,368

Conveyance	Underlying Oil Production (Bbls) 2018	2017
Kansas	**8,621**	7,049
Oklahoma	**138,880**	143,099
Wyoming	**7,833**	6,204
Total	**155,334**	156,352

Pricing and Sales Information

XTO Energy sells most of its natural gas production directly to third parties, and a portion is sold to certain of XTO Energy's wholly owned subsidiaries based on a weighted average sales price. The weighted average sales price received from the subsidiary is based upon sales to third parties for the best available price. Oil production is generally marketed at the wellhead to third parties at the best available price. XTO Energy arranges for some of its natural gas to be processed by unaffiliated third parties and markets the natural gas liquids. Some of the natural gas attributable to the underlying properties is marketed under contracts existing at Trust inception. Contracts covering production from the Ringwood area of the Major County area are generally for the life of the lease. The contract with an unaffiliated third party for the majority of production from the Hugoton area is in effect through 2019. If new contracts are entered with unaffiliated third parties, the proceeds from sales under those new contracts will be included in gross proceeds from the underlying properties. If new contracts are entered with any subsidiary of XTO Energy, it may charge XTO Energy a fee that may not exceed 2% of the sales price of the oil and natural gas received from unaffiliated parties. The sales price is net of any deductions for transportation from the wellhead to the unaffiliated parties and any gravity or quality adjustments. For further information on these arrangements see Significant Properties above.

Regulation

Natural Gas Regulation

The interstate transportation and sale for resale of natural gas is subject to federal regulation, including transportation and storage rates charged, tariffs, and various other matters, by the Federal Energy Regulatory Commission. Federal price controls on wellhead sales of domestic natural gas terminated on January 1, 1993. While natural gas prices are currently unregulated, Congress historically has been active in the area of natural gas regulation. On August 8, 2005, Congress enacted the Energy Policy Act of 2005. The Energy Policy Act, among other things, amended the Natural Gas Act to prohibit market manipulation by any entity, to direct FERC to facilitate market transparency in the market for sale or transportation of physical natural gas in interstate commerce, and to significantly increase the penalties for violations of the Natural Gas Act, the Natural Gas Policy Act of 1978, or FERC rules, regulations or orders thereunder. FERC has promulgated regulations to implement the Energy Policy Act, including enforcement rules and new annual reporting requirements for certain sellers of natural gas. It is impossible to predict whether new legislation to regulate natural gas might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, such proposals might have on the operations of the underlying properties.

Federal Regulation of Oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at market prices. The net price received from the sale of these products is affected by market transportation costs. Under rules adopted by FERC effective January 1995, interstate oil pipelines can change rates based on an inflation index, though other rate mechanisms may be used in specific circumstances.

On December 19, 2007, the President signed into law the Energy Independence & Security Act of 2007 (PL 110-140). The EISA, among other things, prohibits market manipulation by any person in connection with the purchase or sale of crude oil, gasoline or petroleum distillates at wholesale in contravention of such rules and regulations that the Federal Trade Commission may prescribe, directs the Federal Trade Commission to enforce the regulations, and establishes penalties for violations thereunder. XTO Energy has advised the Trustee that it cannot predict the impact of future government regulation on any crude oil, condensate or natural gas liquids facilities, sales or transportation transactions.

Environmental Regulation

Companies that are engaged in the oil and gas industry are affected by federal, state and local laws regulating the discharge of materials into the environment. Those laws may impact operations of the underlying properties. No material expenses have been incurred on the underlying properties in complying with environmental laws and regulations. XTO Energy does not expect that future compliance will have a material adverse effect on the Trust.

There is an increased focus by local, national and international regulatory bodies on greenhouse gas (GHG) emissions and climate change. Several states have adopted climate change legislation and regulations, and various other regulatory bodies have announced their intent to regulate GHG emissions or adopt climate change regulations. As these regulations are under development, XTO Energy is unable to predict the total impact of the potential regulations upon the operators of the underlying properties, and it is possible that operators of the underlying properties could face increases in operating costs in order to comply with climate change or GHG emissions legislation, which costs could reduce net proceeds payable to the Trust and Trust distributions.

State Regulation

The various states regulate the production and sale of oil and natural gas, including imposing requirements for obtaining drilling permits, the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and gas resources. The rates of production may be regulated and the maximum daily production allowables from both oil and gas wells may be established on a market demand or conservation basis, or both.

Federal Income Taxes

For federal income tax purposes, the Trust constitutes a fixed investment trust that is taxed as a grantor trust. A grantor trust is not subject to tax at the trust level. The unitholders are considered to own the Trust's income and principal as though no trust were in existence. The income of the Trust is deemed to have been received or accrued by each unitholder at the time such income is received or accrued by the Trust and not when distributed by the Trust. Impairment for book purposes will not result in a loss for tax purposes for the unitholders until the loss is recognized.

Because the Trust is a grantor trust for federal tax purposes, each unitholder is taxed directly on his proportionate share of income, deductions and credits of the Trust consistent with each such unitholder's taxable year and method of accounting and without regard to the taxable year or method of accounting employed by the Trust. The income of the Trust consists primarily of a specified share of the net profits from the sale of oil and natural gas produced from the underlying properties. During 2018, the Trust incurred administration expenses and earned interest income on funds held for distribution and for the cash reserve maintained for the payment of contingent and future obligations of the Trust.

The Trust generally allocates its items of income, gain, loss and deduction between transferors and transferees of the units each month based upon the ownership of the Trust units on the monthly record date, instead of on the basis of the date a particular unit is transferred. It is possible that the IRS could disagree with this allocation method and could assert that income and deductions of the Trust should be determined and allocated on a daily or prorated basis, which could require adjustments to the tax returns of the unitholders affected by the issue and result in an increase in the administrative expense of the Trust in subsequent periods.

The net profits interests constitute "economic interests" in oil and gas properties for federal tax purposes. Each unitholder is entitled to amortize the cost of the units through cost depletion over the life of the net profits interests or, if greater, through percentage depletion equal to 15 percent of gross income, limited to 100% of the net income from such net profits interest. Unlike cost depletion, percentage depletion is not limited to a unitholder's depletable tax basis in the units. Rather, a unitholder is entitled to a percentage depletion deduction as long as the applicable underlying properties generate gross income. Unitholders should compute both percentage depletion and cost depletion from each property and claim the larger amount as a deduction on their income tax returns.

Unitholders must maintain records of their adjusted basis in their Trust units (generally his or her cost less prior depletion deductions), make adjustments for depletion deductions to such basis, and use the adjusted basis for the computation of gain or loss on the disposition of the Trust units.

If a taxpayer disposes of any "Section 1254 property" (certain oil, gas, geothermal or other mineral property), and the adjusted basis of such property includes adjustments for depletion deductions under Section 611 of the Internal Revenue Code (the "Code"), the taxpayer generally must recapture the amount deducted for depletion as ordinary income (to the extent of gain realized on such disposition). This depletion recapture rule applies to any disposition of property that was placed in service by the taxpayer after December 31, 1986. Detailed rules set forth in Sections 1.1254-1 through 1.1254-6 of the U.S. Treasury Regulations govern dispositions of property after March 13, 1995. The Internal Revenue Service likely will take the position that a unitholder must recapture depletion upon the disposition of a unit.

Interest and net profits income attributable to ownership of units and any gain on the sale thereof are considered portfolio income, and not income from a "passive activity," to the extent a unitholder acquires and holds units as an investment and not in the ordinary course of a trade or business. Therefore, interest and net profits income attributable to ownership of units generally may not be offset by losses from any passive activities.

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

For tax years beginning before January 1, 2018, the highest marginal U.S. federal income tax rate applicable to ordinary income of individuals is 39.6%, and the highest marginal U.S. federal income tax rate applicable to long-term capital gains and qualified dividends of individuals is 20%. For such pre-2018 tax years, such marginal tax rates may be effectively increased by up to 1.2% due to the phaseout of personal exemptions and the limitations on itemized deductions. For such pre-2018 tax years, the highest marginal U.S. federal income tax rate applicable to corporations is 35%, and such rate applies to both ordinary income and capital gains.

Section 1411 of the Code imposes a 3.8% Medicare tax on certain investment income earned by individuals, estates, and trusts. For these purposes, investment income generally will include a unitholder's allocable share of the Trust's interest and royalty income plus the gain recognized from a sale of Trust units. In the case of an individual, the tax is imposed on the lesser of (i) the individual's net investment income from all investments, or (ii) the amount by which the individual's modified adjusted gross income exceeds specified threshold levels depending on such individual's federal income tax filing status. In the case of an estate or trust, the tax is imposed on the lesser of (i) undistributed net investment income, or (ii) the excess adjusted gross income over the dollar amount at which the highest income tax bracket applicable to an estate or trust begins.

The difference between the per-unit taxable income for any period and the per-unit cash distributions, if any, reported for such period is attributable to (i) items that reduce cash distributions but are not currently deductible, such as an increase in the cash reserve maintained by the Trust for the payment of future expenditures; (ii) the current deduction of expenses that are paid with amounts previously reserved; (iii) items that increase cash distributions but do not constitute taxable income, such as a decrease in the cash reserve maintained by the Trust and/or a return of capital; and (iv) items that constitute taxable income due to the recovery of prior period expense adjustments. Because of these types of items and when the Trustee elects to reserve amounts from monthly distributions to maintain an administrative expense reserve, the taxable income per period frequently differs from the actual amount distributed to unitholders.

Individuals may also incur expenses in connection with the acquisition or maintenance of Trust units. For tax years beginning before January 1, 2018, these expenses, which are different from a unitholder's share of the Trust's administrative expenses discussed above, may be deductible as "miscellaneous itemized deductions" only to the extent that such expenses exceed 2 percent of the individual's adjusted gross income. Under the TCJA, for tax years beginning after December 31, 2017 and before January 1, 2026, miscellaneous itemized deductions are not allowed.

Pursuant to the Foreign Account Tax Compliance Act (commonly referred to as "FATCA"), distributions from the Trust to "foreign financial institutions" and certain other "non-financial foreign entities" may be subject to U.S. withholding taxes. Specifically, certain "withholdable payments" (including certain royalties, interest and other gains or income from U.S. sources) made to a foreign financial institution or non-financial foreign entity will generally be subject to the withholding tax unless the foreign financial institution or non-financial foreign entity complies with certain information reporting, withholding, identification, certification and related requirements imposed by FATCA. Foreign financial institutions located in jurisdictions that have an intergovernmental agreement with the United States governing FATCA may be subject to different rules.

The Treasury Department issued guidance providing that the FATCA withholding rules described above generally will apply to qualifying payments made after June 30, 2014. Foreign unitholders are encouraged to consult their own tax advisors regarding the possible implications of these withholding provisions on their investment in Trust units.

Some Trust units are held by middlemen, as such term is broadly defined in U.S. Treasury Regulations (and includes custodians, nominees, certain joint owners, and brokers holding an interest for a customer in street name, collectively referred to herein as "middlemen"). Therefore, the Trustee considers the Trust to be a non-mortgage widely held fixed investment trust ("WHFIT") for U.S. federal income tax purposes. Simmons Bank, EIN: 71-0162300, 2911 Turtle Creek Blvd, Suite 850, Dallas, Texas, 75219, telephone number 1-855-588-7839, email address Trustee@hgt-hugoton.com, is the representative of the Trust that will provide tax information in accordance with applicable U.S. Treasury Regulations governing the information reporting requirements of the Trust as a WHFIT. Tax information is also posted by the Trustee at www.hgt-hugoton.com. Notwithstanding the foregoing, the middlemen holding Trust units on behalf of unitholders, and not the Trustee of the Trust, are solely responsible for complying with the information reporting requirements under the U.S. Treasury Regulations with respect to such Trust units, including the issuance of IRS Forms 1099 and certain written tax statements.

Unitholders whose Trust units are held by middlemen should consult with such middlemen regarding the information that will be reported to them by the middlemen with respect to the Trust units.

Unitholders should consult their tax advisors regarding trust tax compliance matters.

State Income Taxes

All revenues from the Trust are from sources within Kansas, Oklahoma or Wyoming. Kansas and Oklahoma each impose a state income tax, which is potentially applicable to income from the net profits interests located in each of those states. Because it distributes all of its net income to unitholders, the Trust is not taxed at the trust level in Kansas or Oklahoma. While the Trust does not owe tax, the Trustee is required to file an Oklahoma income tax return reflecting the income and deductions of the Trust attributable to properties located in the state, along with a schedule that includes information regarding distributions to unitholders. Oklahoma taxes the income of nonresidents from real property located within the state, and the Trust has been advised by counsel that Oklahoma will tax nonresidents on income from the net profits interest located within the state. Oklahoma also imposes a corporate income tax that may apply to unitholders organized as corporations (subject to certain exceptions for S corporations and limited liability companies, depending on their treatment for federal tax purposes).

Kansas also taxes the income of nonresidents from property located within the state. However, the Trust will not file a Kansas income tax return for the 2018 tax year because the Trust had no revenues, income or deductions in 2018 attributable to properties located in Kansas. The Trust did not file a return with Kansas for the 2017 and 2016 tax years for the same reason.

Wyoming does not impose a state income tax.

Each unitholder should consult his or her own tax advisor regarding state income tax requirements, if any, applicable to such person's ownership of Trust units.

State Tax Withholding

Several states have enacted legislation requiring state income tax withholding from payments to nonresident recipients of oil and gas proceeds. After consultation with its tax counsel, the Trustee believes that it is not required to withhold on payments made to the unitholders. However, regulations are subject to change by the various states, which could change this conclusion. Should amounts be withheld on payments made to the Trust or the unitholders, distributions to the unitholders would be reduced by the required amount, subject to the filing of a claim for refund by the Trust or unitholders for such amount.

Other Regulation

The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws, including, but not limited to, regulations and laws relating to environmental protection, occupational safety, resource conservation and equal employment opportunity. XTO Energy has advised the Trustee that it does not believe that compliance with these laws will have any material adverse effect upon the unitholders.

Item 3. *Legal Proceedings*

In December 2010, a royalty class action lawsuit was filed against XTO Energy styled *Chieftain Royalty Company v. XTO Energy Inc.* in Coal County District Court, Oklahoma. XTO Energy removed the case to federal court in the Eastern District of Oklahoma. The plaintiffs allege that XTO Energy wrongfully deducted fees from royalty payments on Oklahoma wells, failed to make diligent efforts to secure the best terms available for the sale of gas and its constituents, and demanded an accounting to determine whether they have been fully and fairly paid gas royalty interests. The case was certified as a class action in April 2012, then decertified in July 2013.

XTO Energy advised the Trustee that in December 2017, it reached a tentative settlement with the plaintiffs for $80 million and up to an additional $750 thousand for costs to administer the settlement following final approval. In March 2018, XTO Energy advised the Trustee that it believed the portion of the settlement that relates to the Trust could be as much as $20 million, but the settlement allocable to the Trust could not be finally determined until after the judge approved the plaintiffs' final plan of allocation. On July 27, 2018, plaintiffs submitted their final plan of allocation which was approved by the court on the same date. Based on the final plan of allocation XTO Energy has advised the Trustee that it believes approximately $24.3 million in additional production costs should be allocated to the Trust. On May 2, 2018, the Trustee submitted a demand for arbitration styled *Simmons Bank (successor to Southwest Bank and Bank of America, N.A.) vs. XTO Energy Inc*. (the "Arbitration") through the American Arbitration Association seeking a declaratory judgment that the *Chieftain* settlement is not a production cost and that XTO Energy is prohibited from charging the settlement as a production cost under the conveyance or otherwise reducing the Trust's payments now or in the future as a result of the *Chieftain* litigation. In the Arbitration, the Trustee also made claims for disputed amounts on the computation of the Trust's net proceeds for 2014 through 2016 in excess of $5 million. XTO Energy filed its answer denying the Trustee's claims. The Arbitration panel has been selected. The hearing on the claims related to the *Chieftain* settlement has been scheduled for October 7, 2019. The remaining claims related to the computation of the Trust's net proceeds were bifurcated and will be heard at a later date, which is still to be determined.

If the approximately $24.3 million allocated portion of the *Chieftain* settlement results in an adjustment to the Trust's share of net proceeds, it would result in additional excess costs under the Oklahoma conveyance that would likely result in no distributions under the Oklahoma conveyance for several years, or more depending on the results of operations of the underlying properties, while these additional excess costs are recovered.

Certain of the underlying properties are involved in various other lawsuits and governmental proceedings arising in the ordinary course of business. XTO Energy has advised the Trustee that it does not believe that the ultimate resolution of these claims will have a material effect on the financial position or liquidity of the Trust, but may have an effect on annual distributable income.

Item 4. *Mine Safety Disclosures*

Not Applicable.

PART II

Item 5. *Market for Units of the Trust, Related Unitholder Matters and Trust Purchases of Units*

Units of Beneficial Interest

The units of beneficial interest in the Trust began trading on the New York Stock Exchange on April 9, 1999 under the symbol "HGT." On August 27, 2018, the Trust units were delisted from the NYSE and began to be quoted on the OTCQX, which is maintained by the OTC Market Group Inc., under the symbol "HGTXU." Any quotations on the OTCQX reflect inter-dealer prices, without retail mark-up, mark-down, or commission and may not necessarily reflect actual transactions.

At December 31, 2018, there were 40,000,000 units outstanding and approximately 593 unitholders of record; 39,427,406 of these units were held by depository institutions.

The Trust has no equity compensation plans, nor has it purchased any units during the period covered by this report.

See "Item 1. Business" for a description of the Trustee's obligations to make monthly distributions and how the monthly distribution amount is determined under the indenture.

Item 6. *Selected Financial Data*

Not required for smaller reporting companies; the Trust has elected to omit this information.

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

Calculation of Net Profits Income

The following is a summary of the calculation of net profits income received by the Trust:

	Year Ended December 31[a]		Three Months Ended December 31[a]	
	2018	2017	2018	2017
Sales Volumes				
Gas (Mcf)[b]				
Underlying properties	**12,994,466**	13,903,368	**3,265,229**	3,405,474
Average per day	**35,601**	38,091	**35,492**	37,016
Net profits interests	**447,961**	1,628,427	**—**	341,493
Oil (Bbls)[b]				
Underlying properties	**155,334**	156,352	**34,666**	37,061
Average per day	**426**	428	**377**	403
Net profits interests	**7,627**	26,775	**—**	5,554
Average Sales Prices				
Gas (per Mcf)	**$ 2.69**	$ 2.92	**$ 2.68**	$ 2.88
Oil (per Bbl)	**$ 62.69**	$ 46.47	**$ 67.99**	$ 47.05
Revenues				
Gas sales	**$ 34,963,154**	$40,650,478	**$ 8,765,079**	$ 9,823,346
Oil sales	**9,737,686**	7,264,995	**2,356,923**	1,743,585
Total Revenues	**44,700,840**	47,915,473	**11,122,002**	11,566,931
Costs				
Taxes, transportation and other	**8,178,584**	8,259,657	**2,060,152**	1,990,343
Production expense	**18,131,944**	17,128,387	**4,349,947**	4,193,695
Development costs[c]	**21,802,500**	2,800,000	**7,837,500**	840,000
Overhead	**11,636,835**	11,570,344	**2,917,565**	2,919,732
Excess costs[d]	**(17,037,709)**	1,509,671	**(6,043,162)**	271,652
Total Costs	**42,712,154**	41,268,059	**11,122,002**	10,215,422
Net Proceeds	**1,988,686**	6,647,414	**—**	1,351,509
Net Profits Percentage	**80%**	80%	**80%**	80%
Net Profits Income	**$ 1,590,949**	$ 5,317,931	**$ —**	$ 1,081,207

(a) Because of the two-month interval between time of production and receipt of net profits income by the Trust: 1) oil and gas sales for the year ended December 31 generally relate to twelve months of production for the period November through October, and 2) oil and gas sales for the three months ended December 31 generally relate to production for the period August through October.

(b) Oil and gas sales volumes are allocated to the net profits interests by dividing Trust net cash inflows by average sales prices. As oil and gas prices change, the Trust's allocated production volumes are impacted as the quantity of production necessary to cover expenses changes inversely with price. As such, the underlying property production volume changes may not correlate with the Trust's allocated production volumes in any given period. Therefore, comparative discussion of oil and gas sales volumes is based on the underlying properties.

(c) See Note 5 to Financial Statements under Item 8, Financial Statements and Supplementary Data.

(d) See Note 4 to Financial Statements under Item 8, Financial Statements and Supplementary Data.

Results of Operations

Years Ended December 31, 2018 and 2017

Net profits income for 2018 was $1,590,949, as compared with $5,317,931 for 2017. The 70% decrease in net profits income from 2017 to 2018 was primarily the result of higher development costs ($15.2 million), lower gas prices ($2.5 million), lower oil and gas production ($2.0 million), higher production expenses ($0.8 million), partially offset by excess costs ($14.8 million) and higher oil prices ($2.0 million). Approximately 75% in 2018 and 78% in 2017 of net profits income was derived from natural gas sales.

Trust administration expense was $1,115,904 in 2018 as compared to $804,719 in 2017. Net cash reserve activity was $128,157 in 2018 and $0 in 2017. Cash reserve activity for 2018 included additions of $922,409 which the Trustee reserved for administrative expenses, offset by reductions of $794,252 for the payment of trust expenses. Interest income was $23,152 in 2018 and $7,028 in 2017. Changes in interest income are attributable to fluctuations in net profits income and interest rates. Distributable income was $370,040 or $0.009251 per unit in 2018 and $4,520,240 or $0.113006 per unit in 2017.

Net profits income is recorded when received by the Trust, which is the month following receipt by XTO Energy, and generally two months after oil and gas production. Net profits income is generally affected by three major factors:

1. oil and gas sales volumes;
2. oil and gas sales prices; and
3. costs deducted in the calculation of net profits income.

Volumes

Gas. From 2017 to 2018, underlying gas sales volumes decreased 7% primarily due to natural production decline.

Oil. From 2017 to 2018, underlying oil sales volumes decreased 1% primarily due to natural production decline, partially offset by timing of cash receipts.

The estimated rate of natural production decline on the underlying oil and gas properties is approximately 6% to 8% a year.

Prices

Gas. The 2018 average gas price was $2.69 per Mcf, an 8% decrease from the 2017 average gas price of $2.92 per Mcf. Natural gas prices are affected by the level of North American production, weather, crude oil and natural gas liquids prices, the U.S. economy, storage levels and import levels of liquefied natural gas. Natural gas prices are expected to remain volatile. The average NYMEX price for November 2018 through January 2019 was $3.85 per MMBtu. At March 1, 2019, the average NYMEX gas price for the following 12 months was $2.99 per MMBtu.

Oil. The average oil price for 2018 was $62.69 per Bbl, a 35% increase from the average oil price for 2017 of $46.47 per Bbl. Oil prices are expected to remain volatile. The average NYMEX price for November 2018 through January 2019 was $52.44 per Bbl. At March 1, 2019, the average NYMEX oil price for the following 12 months was $57.30 per Bbl.

Costs

The calculation of net profits income includes deductions for production expense, development costs and overhead since the related underlying properties are working interests.

Taxes, transportation and other. Taxes, transportation and other generally fluctuates with changes in total revenues. Taxes, transportation and other decreased 1% from 2017 to 2018 primarily because of decreased production taxes related to lower gas revenues, partially offset by increased gas deductions related to gathering fees and increased production taxes on higher oil revenues.

Production expense. Production expense increased 6% from 2017 to 2018 primarily because repairs and maintenance, partially offset by decreased other field goods and services.

Development costs. Development costs, which were deducted based on budgeted development costs, were $21.8 million in 2018 and $2.8 million in 2017. In 2018, actual development costs were $8.4 million. At December 31, 2018, cumulative budgeted costs deducted exceeded cumulative actual costs by approximately $13.9 million.

The monthly deduction is based on the current level of development expenditures, budgeted future development costs and the cumulative actual costs under (over) previous deductions. Changes in oil or natural gas prices could impact future development plans on the underlying properties. XTO Energy has advised the Trustee that this monthly deduction will continue to be evaluated and revised as necessary. For further information on development costs, see Note 5 to Financial Statements under Item 8, Financial Statements and Supplementary Data.

Overhead. Overhead is charged by XTO Energy and other operators for administrative expenses incurred to support operations of the underlying properties. Overhead fluctuates based on changes in the active well count and drilling activity on the underlying properties, as well as an annual cost level adjustment.

Excess costs. If monthly costs exceed revenues for any conveyance, these excess costs must be recovered, with accrued interest, from future net proceeds of that conveyance and cannot reduce net profits income from another conveyance. Underlying cumulative excess costs for the Kansas, Oklahoma and Wyoming conveyances remaining as of December 31, 2018 totaled $18.0 million ($14.4 million NPI), including accrued interest of $0.2 million ($0.1 million NPI). For further information on excess costs, including the balance and accrued interest by conveyance, see Note 4 to Financial Statements under Item 8, Financial Statements and Supplementary Data.

Fourth Quarter 2018 and 2017

During fourth quarter 2018 the Trust received net profits income totaling $0 compared with fourth quarter 2017 net profits income of $1,081,207 primarily due to higher development costs ($5.6 million), lower gas prices ($0.5 million), decreased oil and gas production ($0.4 million), increased production expenses ($0.1 million), increased taxes, transportation and other costs ($0.1 million), partially offset by excess costs activity ($5.0 million) and higher oil prices ($0.6 million).

After adding interest income of $6,697 and deducting administration expense of $230,245, and reducing the cash reserve $223,548 for the payment of Trust expenses, distributable income for fourth quarter 2018 was $0 or $0.000000 per unit. Distributable income for fourth quarter 2017 was $985,960 or $0.024649 per unit.

Distributions to unitholders for the quarter ended December 31, 2018 were:

Record Date	Payment Date	Per Unit
October 31, 2018	November 15, 2018	$0.000000
November 30, 2018	December 14, 2018	0.000000
December 31, 2018	January 15, 2019	0.000000
		$0.000000

Volumes

Fourth quarter underlying gas sales volumes decreased 4% from 2017 to 2018 primarily due to natural production decline. Underlying oil sales volumes decreased 6% from 2017 to 2018 primarily due to natural production decline.

Prices

The average fourth quarter 2018 gas price was $2.68 per Mcf, or 7% lower than the fourth quarter 2017 average price of $2.88 per Mcf. The average fourth quarter 2018 oil price was $67.99 per Bbl, or 45% higher than the fourth quarter 2017 average price of $47.05 per Bbl. For further information about product prices, see “Years Ended December 31, 2018 and 2017 – Prices” above.

Costs

Taxes, transportation and other. Taxes, transportation and other increased 4% from fourth quarter 2017 to 2018 primarily because of increased property taxes, production taxes on higher oil revenues and increased gas deductions related to gathering fees, partially offset by decreased production taxes on lower gas revenues.

Production expense. Fourth quarter production expense increased 4% from 2017 to 2018 primarily because of increased repairs and maintenance.

Development costs. Development costs deducted are based on the current level of development expenditures, budgeted future development costs and the cumulative actual costs under (over) previous deductions. The development costs increased 833% from fourth quarter 2017 to 2018, primarily due to the increase in the development budget for the active drilling of four horizontal wells in Major County, Oklahoma, with completions currently scheduled for early 2019. For further information on development costs, see Note 5 to Financial Statements under Item 8, Financial Statements and Supplementary Data.

Overhead. Overhead is charged by XTO Energy and other operators for administrative expenses incurred to support operations of the underlying properties. Overhead fluctuates based on changes in the active well count and drilling activity on the underlying properties, as well as an annual cost level adjustment.

Excess costs. If monthly costs exceed revenues for any conveyance, these excess costs must be recovered, with accrued interest, from future net proceeds of that conveyance and cannot reduce net profits income from another conveyance. For information on excess costs, including the excess cost balance and accrued interest by conveyance, see Note 4 to Financial Statements under Item 8, Financial Statements and Supplementary Data.

Liquidity and Capital Resources

The Trust’s only cash requirement is any declared monthly distribution of its income to unitholders, which is funded by the monthly receipt of net profits income after payment of Trust administration expenses. The Trust is not liable for any production costs or liabilities attributable to the net profits interests. If at any time the Trust receives net profits income in excess of the amount due, the Trust is not obligated to return such overpayment, but future net profits income payable to the Trust will be reduced by the overpayment, plus interest at the prime rate. The Trust may borrow funds required to pay Trust liabilities if fully repaid prior to further distributions to unitholders.

The Trust does not have any transactions, arrangements or other relationships with unconsolidated entities or persons that could materially affect the Trust’s liquidity or the availability of capital resources.

The accompanying financial statements have been prepared assuming that the Trust will continue as a going concern. Financial statements prepared on a going concern basis assume the realization of assets and the settlement of liabilities in the normal course of business. Increases in excess costs for the Kansas, Oklahoma and Wyoming conveyances have resulted in no net proceeds to the Trust for the last nine months of 2018 and a reduction in the Trust's expense reserve. These conditions raise substantial doubt about the Trust's ability to continue as a going concern as the Trust may not have, based on the current estimated administrative expenses, sufficient cash to meet its obligations during the one year period after the date the financial statements are issued. Factors attributable to the potential cash shortage are primarily the previously disclosed increase in the 2018 development budget to include drilling costs of four horizontal wells in Major County, Oklahoma ($19.6 million net to the Trust) which have created an excess cost position on the Oklahoma conveyance. Additionally, excess cost positions on the Kansas and Wyoming conveyances have resulted in no net proceeds to the Trust for 2018. The Trustee has prepared a preliminary budget estimating the administrative expenses for the next 12 months which assumes no cash inflow from either net profits income or from other sources. This budget estimates that the expense reserve will be depleted by approximately February 2020. If either income or expenses differ from the assumptions in the Trustee's preliminary budget, this date may be sooner or later than the estimate. Both the Trustee and XTO Energy believe the Trust could obtain additional financing, including by borrowing under one or more debt instruments, in an amount sufficient to pay its obligations for the next year. This outcome would ensure that the Trust could continue as a going concern; however, there is no assurance that such additional financing could be obtained. If the Trust obtains debt financing, any funds borrowed must be repaid in full, including accrued interest, before distributions to unitholders could be made. Subsequent to December 31, 2018, the Trust received net profits income from the Wyoming conveyance in an amount that covered all of the Trust's administrative expenses in March 2019 and allowed for a partial replenishment of the expense reserve. However, the net profits income in March 2019 is not necessarily indicative of future cash inflows for the next 12 months. The Trust's consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

Greenhouse Gas Emissions and Climate Change Regulation

There is an increased focus by local, national and international regulatory bodies on greenhouse gas (GHG) emissions and climate change. Several states have adopted climate change legislation and regulations, and various other regulatory bodies have announced their intent to regulate GHG emissions or adopt climate change regulations. The climate accord reached at the Conference of the Parties (COP21) in Paris set many new goals, and while many related policies are still emerging, XTO Energy has informed the Trustee that it continues to anticipate that such policies will increase the cost of carbon dioxide emissions over time. As these regulations are under development, XTO Energy is unable to predict the total impact of the potential regulations upon the operators of the underlying properties, and it is possible that the operators of the underlying properties could face increases in operating costs in order to comply with climate change or GHG emissions legislation, which costs could reduce net proceeds payable to the Trust and Trust distributions.

Off-Balance Sheet Arrangements

The Trust has no off-balance sheet financing 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.

Contractual Obligations

Not required for smaller reporting companies; the Trust has elected to omit this information.

Related Party Transactions

XTO Energy operates approximately 95% of the underlying properties. In computing net proceeds, XTO Energy deducts an overhead charge for reimbursement of administrative expenses on the underlying properties it operates. As of December 31, 2018, the monthly overhead charge, based on the number of operated wells, was approximately $938,000 ($750,400 net to the Trust) and is subject to annual adjustment based on an oil and gas industry index as defined in the Trust Indenture.

Certain of XTO Energy's wholly owned subsidiaries purchase natural gas and provide services for the properties operated by XTO Energy. In the Hugoton area, Timberland provides gathering from the wellhead to DCP's gathering system for approximately $0.75 per Mcf. A portion of the gas production in Major County, Oklahoma is sold to Ringwood Gathering Company ("RGC") for a price based upon third party sales. RGC retains approximately $0.31 per Mcf as a compression and gathering fee. For further information regarding natural gas sales from the underlying properties to affiliates of XTO Energy, see Significant Properties, under Item 2, Properties.

Total gas sales from the underlying properties to XTO Energy's wholly owned subsidiaries were $5.8 million for 2018, or 16% of total gas sales, $12.3 million for 2017, or 30% of total gas sales.

XTO Energy has advised the Trustee that, effective April 1, 2017, Cross Timbers Energy Services, Inc. ("CTES"), a wholly owned marketing subsidiary of XTO Energy, has assigned all gas sales contracts for production from the underlying properties to XTO Energy. XTO Energy will directly market and sell the gas to third parties. XTO Energy has advised the Trustee that there are no changes to the terms of the contracts related to the assignment and no impact on Trust distributions.

On June 25, 2010, XTO Energy became a wholly owned subsidiary of Exxon Mobil Corporation.

Critical Accounting Policies

The financial statements of the Trust are significantly affected by its basis of accounting and estimates related to its oil and gas properties and proved reserves, as summarized below.

Basis of Accounting

The Trust's financial statements are prepared on a modified cash basis, which is a comprehensive basis of accounting other than U.S. GAAP. This method of accounting is consistent with reporting of taxable income to Trust unitholders. The most significant differences between the Trust's financial statements and those prepared in accordance with U.S. GAAP are:

1. Net profits income is recognized in the month received rather than accrued in the month of production.
2. Expenses are recognized when paid rather than when incurred.
3. Cash reserves may be established by the Trustee for certain contingencies that would not be recorded under U.S. GAAP.

This comprehensive basis of accounting other than U.S. 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. For further information regarding the Trust's basis of accounting, see Note 2 to Financial Statements under Item 8, Financial Statements and Supplementary Data.

All amounts included in the Trust's financial statements are based on cash amounts received or disbursed, or on the carrying value of the net profits interests, which was derived from the historical cost of the interests at the date of their transfer from XTO Energy, less accumulated amortization to date. Accordingly, there are no fair value estimates included in the financial statements based on either exchange or non-exchange trade values.

Impairment of Net Profits Interest

The Trustee reviews the Trust's net profits interests ("NPI") in oil and gas properties for impairment whenever events or circumstances indicate that the carrying value of the NPI may not be recoverable. In general, the Trustee does not view temporarily low prices as an indication of impairment. The markets for crude oil and natural gas have a history of significant price volatility and though prices will occasionally drop significantly, industry prices over the long term will continue to be driven by market supply and demand. If events and circumstances indicated that the carrying value may not be recoverable, the Trustee would use the estimated undiscounted future net cash flows from the NPI to evaluate the recoverability of the Trust assets. If the undiscounted future net cash flows from the NPI are less than the NPI carrying value, the Trust would recognize an impairment loss for the difference between the NPI carrying value and the estimated fair value of the NPI. The determination as to whether the NPI is impaired requires a significant amount of judgment by the Trustee and is based on the best information available to the Trustee at the time of the evaluation. During the second half of 2018, excess costs on properties attributable to the NPI have continued to accumulate, primarily due to the increase in the development budget for the drilling of four horizontal wells in Major County, Oklahoma, which are currently scheduled to be completed in early 2019. The Trustee has considered the accumulation of these excess costs as part of its monitoring process and has concluded that there have been no events or changes in circumstances to indicate the carrying value of the NPI may not be recoverable, and there was no impairment of the assets as of December 31, 2018.

Oil and Gas Reserves

The proved oil and gas reserves for the underlying properties are estimated by independent petroleum engineers. The estimated reserves for the underlying properties are then used by XTO Energy to calculate the estimated oil and gas reserves attributable to the net profits interests. 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, may justify revision of such estimates. Because proved reserves are required to be estimated using 12-month average prices, based on the first-day-of-the-month price for each month in the period, estimated reserve quantities can be significantly impacted by changes in product prices. Accordingly, oil and gas quantities ultimately recovered and the timing of production may be substantially different from original estimates.

The standardized measure of discounted future net cash flows and changes in such cash flows, as reported in Note 9 to Financial Statements under Item 8, Financial Statements and Supplementary Data, is prepared using assumptions required by the Financial Accounting Standards Board and the Securities and Exchange Commission. Such assumptions include using 12-month average oil and gas prices, based on the first-day-of-the-month price for each month in the period, and year end costs for estimated future development and production expenditures, including recovery of cumulative excess costs remaining at year end. Discounted future net cash flows are calculated using a 10% rate. Changes in any of these assumptions, including consideration of other factors, could have a significant impact on the standardized measure. Accordingly, the standardized measure does not represent XTO Energy's or the Trustee's estimated current market value of proved reserves.

Forward-Looking Statements

Certain information included in this annual report and other materials filed, or to be filed, by the Trust with the Securities and Exchange Commission (as well as information included in oral statements or other written statements made or to be made by XTO Energy or the Trustee) contain forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended, and Section 27A of the Securities Act of 1933, as amended, relating to the Trust, operations of the underlying properties and the oil and gas industry. Such forward-looking statements may concern, among other things, reserve-to-production ratios, future production, development activities and associated operating expenses, future development plans by area, increased density drilling, maintenance projects, development, production and other costs, oil and gas prices, pricing differentials, proved reserves, future net cash flows, production levels, expense reserve budgets, availability of financing, arbitration, litigation, political and regulatory matters, such as tax and environmental policy, and competition. Such forward-looking statements are based on XTO Energy's and the Trustee's current plans, expectations, assumptions, projections and estimates and are identified by words such as "expects," "intends," "plans," "projects," "anticipates," "predicts," "believes," "goals," "estimates," "should," "could," "would," and similar words that convey the uncertainty of future events. These statements are not guarantees of future performance and involve certain risks, uncertainties and assumptions that are difficult to predict. Therefore, actual financial and operational results may differ materially from expectations, estimates or assumptions expressed in, implied in, or forecasted in such forward-looking statements. Some of the risk factors that could cause actual results to differ materially are explained in Item 1A, Risk Factors.

Item 7A. *Quantitative and Qualitative Disclosures about Market Risk*

Not required for smaller reporting companies; the Trust has elected to omit this information.

Item 8. ***Financial Statements and Supplementary Data***

All financial statement schedules are omitted as they are inapplicable or the required information has been included in the consolidated financial statements or notes thereto.

Report of Independent Registered Public Accounting Firm

To the Unitholders of Hugoton Royalty Trust and
Simmons Bank, as Trustee

Opinion on the Financial Statements

We have audited the accompanying statements of assets, liabilities, and trust corpus of Hugoton Royalty Trust (the "Trust") as of December 31, 2018 and 2017, and the related statements of distributable income and of changes in trust corpus for the years then ended, including the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the assets, liabilities and trust corpus of the Trust as of December 31, 2018 and 2017, and its distributable income and its changes in trust corpus for the years then ended in conformity with the modified cash basis of accounting described in Note 2.

Substantial Doubt About the Trust's Ability to Continue as a Going Concern

The accompanying financial statements have been prepared assuming that the Trust will continue as a going concern. As discussed in Note 2 to the financial statements, increases in excess costs have led to a reduction in net profits income available to the Trust. These factors have resulted in a decline to the expense reserve available to the Trust for the payment of its obligations which raise substantial doubt about its ability to continue as a going concern. The Trustee's plans in regard to these matters are also described in Note 2. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

Basis for Opinion

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

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

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

Basis of Accounting

As described in Note 2, these financial statements were prepared on the modified cash basis of accounting, which is a comprehensive basis of accounting other than generally accepted accounting principles.

/s/ PricewaterhouseCoopers LLP

Dallas, Texas
March 29, 2019

We have served as the Trust's auditor since 2011.

HUGOTON ROYALTY TRUST

STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

	December 31	
	2018	**2017**
Assets		
Cash and short-term investments	**$ 1,128,157**	$ 1,433,640
Net profits interests in oil and gas properties – net (Notes 1 and 2)	**15,816,990**	16,379,749
	$16,945,147	$17,813,389
Liabilities and Trust Corpus		
Distribution payable to unitholders	**$ —**	$ 433,640
Expense reserve[(a)]	**1,128,157**	1,000,000
Trust corpus (40,000,000 units of beneficial interest authorized and outstanding)	**15,816,990**	16,379,749
	$16,945,147	$17,813,389

(a) The expense reserve allows the Trustee to pay its obligations should it be unable to pay them out of the net profits income.

STATEMENTS OF DISTRIBUTABLE INCOME

	Year Ended December 31	
	2018	**2017**
Net profits income	**$1,590,949**	$5,317,931
Interest income	**23,152**	7,028
Total income	**1,614,101**	5,324,959
Administration expense	**1,115,904**	804,719
Cash reserves withheld (used) for Trust expenses	**128,157**	—
Distributable income	**$ 370,040**	$4,520,240
Distributable income per unit (40,000,000 units)	**$ 0.009251**	$ 0.113006

STATEMENTS OF CHANGES IN TRUST CORPUS

	Year Ended December 31	
	2018	**2017**
Trust corpus, beginning of year	**$16,379,749**	$ 26,885,503
Amortization of net profits interests	**(562,759)**	(10,505,754)
Distributable income	**370,040**	4,520,240
Distributions declared	**(370,040)**	(4,520,240)
Trust corpus, end of year	**$15,816,990**	$ 16,379,749

See accompanying notes to financial statements.

HUGOTON ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS

1. Trust Organization and Provisions

Hugoton Royalty Trust (the "Trust") was created on December 1, 1998 by XTO Energy Inc. (formerly known as "Cross Timbers Oil Company"). Effective on that date, XTO Energy conveyed 80% net profits interests in certain predominantly gas-producing working interest properties in Kansas, Oklahoma and Wyoming to the Trust under separate conveyances for each of the three states. In exchange for the conveyances of the net profits interests to the Trust, XTO Energy received 40 million units of beneficial interest in the Trust. The Trust's initial public offering was in April 1999. The majority of the underlying working interest properties are currently owned and operated by XTO Energy (Note 7).

Simmons Bank is the Trustee for the Trust. The Trust indenture provides, among other provisions, that:

1. the Trust cannot engage in any business activity or acquire any assets other than the net profits interests and specific short-term cash investments;
2. the Trust may dispose of all or part of the net profits interests if approved by a vote of holders of 80% or more of the outstanding Trust units, or upon Trust termination. Otherwise, the Trust is required to sell up to 1% of the value of the net profits interests in any calendar year, pursuant to notice from XTO Energy of its desire to sell the related underlying properties. Any sale must be for cash with 80% of the proceeds distributed to the unitholders on the next declared distribution;
3. the Trustee may establish a cash reserve for payment of any liability that is contingent or not currently payable;
4. the Trustee may borrow funds to pay Trust liabilities if repaid in full prior to further distributions to unitholders;
5. the Trustee will make monthly cash distributions to unitholders (Note 3); and
6. the Trust will terminate upon the first occurrence of:
    a) disposition of all net profits interests pursuant to terms of the Trust indenture,
    b) gross proceeds from the underlying properties falling below $1 million per year for two successive years, or
    c) a vote of holders of 80% or more of the outstanding Trust units to terminate the Trust in accordance with provisions of the Trust indenture.

2. Basis of Accounting

The financial statements of the Trust are prepared on the following basis and are not intended to present financial position and results of operations in conformity with U.S. GAAP:

1. Net profits income is recorded in the month received by the Trustee (Note 3);
2. Interest income, interest to be received and distribution payable to unitholders include interest to be earned on net profits income from the monthly record date (last business day of the month) through the date of the next distribution;
3. Trust expenses are recorded based on liabilities paid and cash reserves established by the Trustee for liabilities and contingencies; and
4. Distributions to unitholders are recorded when declared by the Trustee (Note 3).

The most significant differences between the Trust's financial statements and those prepared in accordance with U.S. GAAP are:

1. Net profits income is recognized in the month received rather than accrued in the month of production.
2. Expenses are recognized when paid rather than when incurred.
3. Cash reserves may be established by the Trustee for certain contingencies that would not be recorded under U.S. GAAP.

This comprehensive basis of accounting 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.

Most accounting pronouncements apply to entities whose financial statements are prepared in accordance with U.S. GAAP, directing such entities to accrue or defer revenues and expenses in a period other than when such revenues were received or expenses were paid. Because the Trust's financial statements are prepared on the modified cash basis, as described above, most accounting pronouncements are not applicable to the Trust's financial statements.

Impairment of Net Profits Interest

The Trustee reviews the Trust's net profits interests ("NPI") in oil and gas properties for impairment whenever events or circumstances indicate that the carrying value of the NPI may not be recoverable. In general, the Trustee does not view temporarily low prices as an indication of impairment. The markets for crude oil and natural gas have a history of significant price volatility and though prices will occasionally drop significantly, industry prices over the long term will continue to be driven by market supply and demand. If events and circumstances indicated that the carrying value may not be recoverable, the Trustee would use the estimated undiscounted future net cash flows from the NPI to evaluate the recoverability of the Trust assets. If the undiscounted future net cash flows from the NPI are less than the NPI carrying value, the Trust would recognize an impairment loss for the difference between the NPI carrying value and the estimated fair value of the NPI. The determination as to whether the NPI is impaired requires a significant amount of judgment by the Trustee and is based on the best information available to the Trustee at the time of the evaluation. During the second half of 2018, excess costs on properties attributable to the NPI have continued to accumulate, primarily due to the increase in the development budget for the drilling of four horizontal wells in Major County, Oklahoma, which are currently scheduled to be completed in early 2019. The Trustee has considered the accumulation of these excess costs as part of its monitoring process and has concluded that there have been no events or changes in circumstances to indicate the carrying value of the NPI may not be recoverable, and there was no impairment of the assets as of December 31, 2018.

Liquidity and Going Concern

The accompanying financial statements have been prepared assuming that the Trust will continue as a going concern. Financial statements prepared on a going concern basis assume the realization of assets and the settlement of liabilities in the normal course of business. Increases in excess costs for the Kansas, Oklahoma and Wyoming conveyances have resulted in no net proceeds to the Trust for the last nine months of 2018 and a reduction in the Trust's expense reserve. These conditions raise substantial doubt about the Trust's ability to continue as a going concern as the Trust may not have, based on the current estimated administrative expenses, sufficient cash to meet its obligations during the one year period after the date the financial statements are issued. Factors attributable to the potential cash shortage are primarily the previously disclosed increase in the 2018 development budget to include drilling costs of four horizontal wells in Major County, Oklahoma ($19.6 million net to the Trust) which have created an excess cost position on the Oklahoma conveyance. Additionally, excess cost positions on the Kansas and Wyoming conveyances have resulted in no net proceeds to the Trust for 2018. The Trustee has prepared a preliminary budget estimating the administrative expenses for the next 12 months which assumes no cash inflow from either net profits income or from other sources. This budget estimates that the expense reserve will be depleted by approximately February 2020. If either income or expenses differ from the assumptions in the Trustee's preliminary budget, this date may be sooner or later than the estimate. Both the Trustee and XTO Energy believe the Trust could obtain additional financing, including by borrowing under one or more debt instruments, in an amount sufficient to pay its obligations for the next year. This outcome would ensure that the Trust could continue as a going concern; however, there is no assurance that such additional financing could be obtained. If the Trust obtains debt financing, any funds borrowed must be repaid in full, including accrued interest, before distributions to unitholders could be made. Subsequent to December 31, 2018, the Trust received net profits income from the Wyoming conveyance in an amount that covered all of the Trust's administrative expenses in March 2019 and allowed for a partial replenishment of the expense reserve. However, the net profits income in March 2019 is not necessarily indicative of future cash inflows for the next 12 months. The Trust's consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

Net profits interests in oil and gas properties

The initial carrying value of the net profits interests of $247,066,951 represents XTO Energy's historical net book value for the interests on December 1, 1998, the date of the transfer to the Trust. During the second quarter 2016, the carrying value of the NPI was written down to its fair value of $28,801,000, resulting in an impairment of $57,306,527 charged directly to Trust corpus. Amortization of the net profits interests is calculated on a unit-of-production basis and charged directly to Trust corpus. Accumulated amortization was $173,943,434 as of December 31, 2018 and $173,380,675 as of December 31, 2017.

3. Distributions to Unitholders

The Trustee determines the amount to be distributed to unitholders each month by totaling net profits income, interest income and other cash receipts, and subtracting liabilities paid and adjustments in cash reserves established by the Trustee. The resulting amount is distributed to unitholders of record within ten business days after the monthly record date, which is the last business day of the month.

Net profits income received by the Trustee consists of net proceeds received in the prior month by XTO Energy from the underlying properties, multiplied by 80%. Net proceeds are the gross proceeds received from the sale of production, less costs. Costs generally include applicable taxes, transportation, legal and marketing charges, production expense, development and drilling costs, and overhead.

XTO Energy, as owner of the underlying properties, computes net profits income separately for each of the three conveyances (one for each of the states of Kansas, Oklahoma and Wyoming). If costs exceed revenues for any conveyance, such excess costs must be recovered, with accrued interest, from future net proceeds of that conveyance and cannot reduce net profits income from the other conveyances (Note 4).

4. Excess Costs

If monthly costs exceed revenues for any of the three conveyances (one for each of the states of Kansas, Oklahoma and Wyoming), such excess costs must be recovered, with accrued interest, from future net proceeds of that conveyance and cannot reduce net proceeds from other conveyances.

The following summarizes excess costs activity, cumulative excess costs balance and accrued interest to be recovered by conveyance:

	Underlying			
	KS	OK	WY	Total
Cumulative excess costs remaining at 12/31/17	$ 771,556	$ —	$ —	$ 771,556
Net excess costs (recovery) for the quarter ended 3/31/18	72,191	—	32,365	104,556
Net excess costs (recovery) for the quarter ended 6/30/18	20,283	4,665,654	486,350	5,172,287
Net excess costs (recovery) for the quarter ended 9/30/18	90,361	5,145,818	481,526	5,717,705
Net excess costs (recovery) for the quarter ended 12/31/18	(57,813)	5,764,759	336,215	6,043,161
Cumulative excess costs remaining at 12/31/18	896,578	15,576,231	1,336,456	17,809,265
Accrued interest at 12/31/18[a]	161,314	—	25,158	186,472
Total remaining to be recovered at 12/31/18	$1,057,892	$15,576,231	$1,361,614	$17,995,737

	NPI			
	KS	OK	WY	Total
Cumulative excess costs remaining at 12/31/17	$ 617,246	$ —	$ —	$ 617,246
Net excess costs (recovery) for the quarter ended 3/31/18	57,752	—	25,892	83,644
Net excess costs (recovery) for the quarter ended 6/30/18	16,226	3,732,523	389,080	4,137,829
Net excess costs (recovery) for the quarter ended 9/30/18	72,289	4,116,655	385,221	4,574,165
Net excess costs (recovery) for the quarter ended 12/31/18	(46,250)	4,611,807	268,972	4,834,529
Cumulative excess costs remaining at 12/31/18	717,263	12,460,985	1,069,165	14,247,413
Accrued interest at 12/31/18[a]	129,051	—	20,126	149,177
Total remaining to be recovered at 12/31/18	$ 846,314	$12,460,985	$1,089,291	$14,396,590

(a) XTO has advised the Trustee that it has determined not to accrue interest on the OK excess costs balance at this time.

For the quarter ended December 31, 2018, higher revenues in relation to costs resulted in the net recovery of excess costs on properties underlying the Kansas net profits interests. Increased budgeted development costs caused costs to exceed revenues on properties underlying the Oklahoma net profits interests. Lower gas prices and increased budgeted development costs caused costs to exceed revenues on properties underlying the Wyoming net profits interests.

Underlying cumulative excess costs for the Kansas, Oklahoma and Wyoming conveyances remaining as of December 31, 2018 totaled $18.0 million ($14.4 million NPI), including accrued interest of $0.2 million ($0.1 million NPI).

5. Development Costs

The following summarizes actual development costs, budgeted development costs deducted in the calculation of net profits income, and the cumulative actual costs compared to the amount deducted:

	Year Ended December 31	
	2018	**2017**
Cumulative actual costs under (over) the amount deducted – beginning of period	**$ 537,144**	$ 56,243
Actual costs	**(8,426,453)**	(2,319,099)
Budgeted costs deducted	**21,802,500**	2,800,000
Cumulative actual costs under (over) the amount deducted – end of period	**$13,913,191**	$ 537,144

The monthly deduction is based on the current level of development expenditures, budgeted future development costs and the cumulative actual costs under (over) previous deductions. Changes in oil or natural gas prices could impact future development plans on the underlying properties. XTO Energy has advised the Trustee that this monthly deduction will continue to be evaluated and revised as necessary.

The monthly development cost deduction was $200,000 from the October 2016 distribution through the July 2017 distribution. Due to increased non-operated development activity on properties underlying the Oklahoma net profits interests, the monthly development deduction was increased to $280,000 beginning with the August 2017 distribution through the March 2018 distribution. Due to increased operated development activity on properties underlying the Oklahoma net profits interests, the monthly development deduction was increased to $2,188,000 beginning with the April 2018 distribution through the October 2018 distribution, and increased to $2,825,000 beginning with the November 2018 distribution through the end of 2018.

For further information on 2019 budgeted development costs, see Properties, under Item 2.

6. Income Taxes

For federal income tax purposes, the Trust constitutes a fixed investment trust that is taxed as a grantor trust. A grantor trust is not subject to tax at the trust level. Accordingly, no provision for income taxes has been made in the financial statements. The unitholders are considered to own the Trust's income and principal as though no trust were in existence. The income of the Trust is deemed to have been received or accrued by each unitholder at the time such income is received or accrued by the Trust and not when distributed by the Trust. Impairment for book purposes will not result in a loss for tax purposes for the unitholders until the loss is recognized.

All revenues from the Trust are from sources within Kansas, Oklahoma or Wyoming. Because it distributes all of its net income to unitholders, the Trust has not been taxed at the trust level in Kansas or Oklahoma. While the Trust has not owed tax, the Trustee is generally required to file Kansas and Oklahoma income tax returns reflecting the income and deductions of the Trust attributable to properties located in each state, along with a schedule that includes information regarding distributions to unitholders. However, the Trust will not file a Kansas return for the 2018 tax year because the Trust had no revenues, income or deductions in 2018 attributable to properties located in Kansas. The Trust did not file a return with Kansas for the 2017 tax year for the same reason.

Wyoming does not impose a state income tax.

The Trust could potentially be required to bear a portion of the legal settlement costs arising from the *Chieftain* settlement. For information on contingencies, see Note 8 to Financial Statements. In the event that the Trust is determined to be responsible for such costs, XTO will deduct the costs in its calculation of the net profits income payable to the Trust from the applicable net profits interests. Thus, for unitholders, the legal settlement costs will be reflected through a reduction in net profits income received from the Trust and thus in a reduction in the gross royalty income reported by and taxable to the unitholders. In the event that the Trustee objects to such claimed reductions, the Trustee may also incur legal fees in representing the Trust's interests. For unitholders, such costs would be reflected through an increase in the Trust's administrative expenses, which would be deductible by unitholders in determining the net royalty income from the Trust.

Each unitholder should consult his or her own tax advisor regarding income tax requirements, if any, applicable to such person's ownership of Trust units.

7. XTO Energy Inc.

XTO Energy operates approximately 95% of the underlying properties. In computing net proceeds, XTO Energy deducts an overhead charge for reimbursement of administrative expenses on the underlying properties it operates. As of December 31, 2018, the monthly overhead charge, based on the number of operated wells, was approximately $938,000 ($750,400 net to the Trust) and is subject to annual adjustment based on an oil and gas industry index as defined in the Trust Indenture.

Certain of XTO Energy's wholly owned subsidiaries purchase natural gas and provide services for the properties operated by XTO Energy. In the Hugoton area, Timberland provides gathering from the wellhead to DCP's gathering system for approximately $0.75 per Mcf. A portion of the gas production in Major County, Oklahoma is sold to Ringwood Gathering Company ("RGC") for a price based upon third party sales. RGC retains approximately $0.31 per Mcf as a compression and gathering fee.

Total gas sales from the underlying properties to XTO Energy's wholly owned subsidiaries were $5.8 million for 2018, or 16% of total gas sales, $12.3 million for 2017, or 30% of total gas sales.

XTO Energy has advised the Trustee that, effective April 1, 2017, Cross Timbers Energy Services, Inc. ("CTES"), a wholly owned marketing subsidiary of XTO Energy, has assigned all gas sales contracts for production from the underlying properties to XTO Energy. XTO Energy will directly market and sell the gas to third parties. XTO Energy has advised the Trustee that there are no changes to the terms of the contracts related to the assignment and no impact on Trust distributions.

On June 25, 2010, XTO Energy became a wholly owned subsidiary of Exxon Mobil Corporation.

8. Contingencies

Litigation

Royalty Class Action and Arbitration

In December 2010, a royalty class action lawsuit was filed against XTO Energy styled *Chieftain Royalty Company v. XTO Energy Inc.* in Coal County District Court, Oklahoma. The plaintiffs allege that XTO Energy wrongfully deducted fees from royalty payments on Oklahoma wells, failed to make diligent efforts to secure the best terms available for the sale of gas and its constituents, and demand an accounting to determine whether they have been fully and fairly paid gas royalty interests.

The case was settled in December 2017, and approved by the court in July 2018. The settlement was $80 million and up to an additional $750 thousand for costs to administer the settlement. Based on the final plan of allocation approved by the court, XTO Energy advised the Trustee that it believes approximately $24.3 million in additional production costs should be allocated to the Trust. Based on preliminary information provided to the Trustee by XTO Energy, on May 2, 2018, the Trustee submitted a demand for arbitration styled *Simmons Bank* (*successor to Southwest Bank and Bank of America, N.A.*) *vs. XTO Energy Inc.* (the "Arbitration") through the American Arbitration Association seeking a declaratory judgment that the *Chieftain* settlement is not a production cost and that XTO Energy is prohibited from charging the settlement as a production cost under the conveyance or otherwise reducing the Trust's payments now or in the future as a result of the *Chieftain* litigation. Additionally, in the Arbitration, the Trustee also made claims for disputed amounts on the computation of the Trust's net proceeds for 2014 through 2016 in excess of $5 million. XTO Energy filed its answer denying the Trustee's claims. The Arbitration panel has been selected. The hearing on the claims related to the *Chieftain* settlement has been scheduled for October 7, 2019. The remaining claims related to the computation of the Trust's net proceeds were bifurcated and will be heard at a later date, which is still to be determined.

If the approximately $24.3 million allocated portion of the *Chieftain* settlement results in an adjustment to the Trust's share of net proceeds, it would result in additional excess costs under the Oklahoma conveyance that would likely result in no distributions under the Oklahoma conveyance for several years, or more depending on the results of operations of the underlying properties, while these additional excess costs are recovered.

Other Lawsuits and Governmental Proceedings

Certain of the underlying properties are involved in various other lawsuits and governmental proceedings arising in the ordinary course of business. XTO Energy has advised the Trustee that it does not believe that the ultimate resolution of these claims will have a material effect on the financial position or liquidity of the Trust, but may have an effect on annual distributable income.

Other

Several states have enacted legislation requiring state income tax withholding from payments made to nonresident recipients of oil and gas proceeds. After consultation with its tax counsel, the Trustee believes that it is not required to withhold on payments made to the unitholders. However, regulations are subject to change by the various states, which could change this conclusion. Should amounts be withheld on payments made to the Trust or the unitholders, distributions to the unitholders would be reduced by the required amount, subject to the filing of a claim for refund by the Trust or unitholders for such amount.

9. Supplemental Oil and Gas Reserve Information (Unaudited)

Oil and Natural Gas Reserves

Proved oil and gas reserves have been estimated by independent petroleum engineers. Proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods, and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. Proved developed reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods in which the cost of the required equipment is relatively minor compared with the cost of a new well. Due to the inherent uncertainties and the limited nature of reservoir data, such estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of these reserves may be substantially different from the original estimate. Revisions result primarily from new information obtained from development drilling and production history and from changes in economic factors.

Standardized Measure

The standardized measure of discounted future net cash flows and changes in such cash flows are prepared using assumptions required by the Financial Accounting Standards Board. Such assumptions include the use of 12-month average prices for oil and gas, based on the first-day-of-the-month price for each month in the period, and year end costs for estimated future development and production expenditures to produce the proved reserves, including recovery of cumulative excess costs remaining at year end. Future net cash flows are discounted at an annual rate of 10%. No provision is included for federal income taxes since future net cash flows are not subject to taxation at the trust level.

The standardized measure does not represent management's estimate of future cash flows or the value of proved oil and gas reserves. Probable and possible reserves, which may become proved in the future, are excluded from the calculations. Furthermore, prices used to determine the standardized measure are influenced by supply and demand as affected by recent economic conditions as well as other factors and may not be the most representative in estimating future revenues or reserve data.

Estimated costs to plug and abandon wells on the underlying working interest properties at the end of their productive lives have not been deducted from cash flows since this is not a legal obligation of the Trust. These costs are the legal obligation of XTO Energy as the owner of the underlying working interests and will only be deducted from net proceeds payable to the Trust if net proceeds from the related conveyance exceed such costs when paid, subject to excess cost carryforward provisions (Notes 3 and 4).

The average realized gas prices used to determine the standardized measure were $2.36 per Mcf in 2018, $2.40 per Mcf in 2017, $1.94 per Mcf in 2016 and $2.10 per Mcf in 2015. Oil prices used to determine the standardized measure were based on average realized oil prices of $63.30 per Bbl in 2018, $47.91 per Bbl in 2017, $39.08 per Bbl in 2016 and $46.56 per Bbl in 2015.

Reserve quantities and revenues for the net profits interests were estimated from projections of reserves and revenues attributable to the underlying properties. Since the Trust has defined net profits interests, the Trust does not own a specific percentage of the oil and gas reserves. Oil and gas reserves are allocated to the net profits interests by dividing Trust net cash inflows by 12-month average oil and gas prices. Any fluctuations in 12-month average prices or estimated costs will result in revisions to the estimated reserve quantities allocated to the net profits interests, which may not correlate with revisions of underlying proved reserves.

Proved Reserves

	Underlying Properties		Net Profits Interests	
(in thousands)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)
Balance, December 31, 2015	103,962	1,186	14,487	179
Extensions, additions and discoveries	—	—	—	—
Revisions of prior estimates	3,361	90	(9,224)	(95)
Production – sales volumes	(14,855)	(179)	(1,096)	(18)
Sales in place	—	—	—	—
Balance, December 31, 2016	92,468	1,097	4,167	66
Extensions, additions and discoveries	5	33	3	17
Revisions of prior estimates	39,851	345	10,496	109
Production – sales volumes	(13,903)	(156)	(1,628)	(27)
Sales in place	—	—	—	—
Balance, December 31, 2017	118,421	1,319	13,038	165
Extensions, additions and discoveries	9,388	674	2,513	180
Revisions of prior estimates	6,375	167	(2,313)	106
Production – sales volumes	(12,994)	(155)	(448)	(8)
Sales in place	—	—	—	—
Balance, December 31, 2018	121,190	2,005	12,790	443

Revisions of prior estimates of the proved gas reserves for the underlying properties in each year are primarily because of changes in the gas and oil prices. Revisions for the net profits interests may not correlate with underlying properties in any given year since the Trust's allocated reserves reflect recovery of the Trust's portion of production and development costs at 12-month average prices. Any conveyance where costs exceed revenues will result in zero allocated net profits interests reserves for that conveyance.

Proved Developed Reserves

	Underlying Properties		Net Profits Interests	
(in thousands)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)
December 31, 2015	102,683	1,178	14,411	178
December 31, 2016	91,734	1,097	4,167	66
December 31, 2017	117,667	1,319	12,844	165
December 31, 2018	111,234	1,339	7,979	121

Standardized Measure of Discounted Future Net Cash Flows from Proved Reserves

(in thousands)	December 31 2018	2017	2016
Underlying Properties			
Future cash inflows	$413,046	$347,055	$222,625
Future costs:			
Production	338,719	301,930	209,820
Development	6,687	795	795
Future net cash flows	67,640	44,330	12,010
10% discount factor	29,776	13,125	2,474
Standardized measure	$ 37,864	$ 31,205	$ 9,536
Net Profits Interests			
Future cash inflows	$ 58,139	$ 38,655	$ 10,353
Future production taxes	4,027	3,192	745
Future net cash flows	54,112	35,463	9,608
10% discount factor	23,821	10,499	1,980
Standardized measure	$ 30,291	$ 24,964	$ 7,628

Changes in Standardized Measure of Discounted Future Net Cash Flows from Proved Reserves

(in thousands)	2018	2017	2016
Underlying Properties			
Standardized measure, January 1	$ 31,205	$ 9,536	$ 29,605
Revisions:			
Prices and costs	11,684	25,717	(18,980)
Quantity estimates	14,205	4,667	988
Accretion of discount	2,731	784	2,569
Future development costs	(27,592)	(2,667)	(738)
Production rates and other	687	(586)	(636)
Net revisions	1,715	27,915	(16,797)
Extensions, additions and discoveries	6,932	401	—
Production	(23,791)	(9,447)	(4,947)
Development costs	21,803	2,800	1,675
Sales in place	—	—	—
Net change	6,659	21,669	(20,069)
Standardized measure, December 31	$ 37,864	$31,205	$ 9,536
Net Profits Interests			
Standardized measure, January 1	$ 24,964	$ 7,628	$ 23,683
Extensions, additions and discoveries	5,545	321	—
Accretion of discount	2,185	628	2,055
Revisions of prior estimates, changes in price and other	(812)	21,705	(15,492)
Sales in place	—	—	—
Net profits income	(1,591)	(5,318)	(2,618)
Standardized measure, December 31	$ 30,291	$24,964	$ 7,628

10. Quarterly Financial Data (Unaudited)

The following is a summary of net profits income, distributable income and distributable income per unit by quarter for 2018 and 2017:

	Net Profits Income	Distributable Income	Distributable Income per Unit
2018			
First Quarter	**$1,590,949**	**$ 370,040**	**$0.009251**
Second Quarter	**—**	**—**	**0.000000**
Third Quarter	**—**	**—**	**0.000000**
Fourth Quarter	**—**	**—**	**0.000000**
	$1,590,949	**$ 370,040**	**$0.009251**
2017			
First Quarter	$2,223,626	$1,886,680	$0.047167
Second Quarter	1,324,846	1,150,280	0.028757
Third Quarter	688,252	497,320	0.012433
Fourth Quarter	1,081,207	985,960	0.024649
	$5,317,931	$4,520,240	$0.113006

11. Subsequent Events

None.

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

None.

Item 9A. *Controls and Procedures*

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

The Trustee conducted an evaluation of the Trust's disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended. Based on this evaluation, the Trustee has concluded that the Trust's disclosure controls and procedures were effective as of the end of the period covered by this annual report. In its evaluation of disclosure controls and procedures, the Trustee has relied, to the extent considered reasonable, on information provided by XTO Energy.

Trustee's Report on Internal Control Over Financial Reporting

The Trustee is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) promulgated under the Securities Exchange Act of 1934, as amended. The Trustee conducted an evaluation of the effectiveness of the Trust's internal control over financial reporting based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the Trustee's evaluation under the framework in *Internal Control— Integrated Framework (2013)*, the Trustee concluded that the Trust's internal control over financial reporting was effective as of December 31, 2018.

Changes in Internal Control Over Financial Reporting

There were no changes in the Trust's internal control over financial reporting during the quarter ended December 31, 2018 that have materially affected, or are reasonably likely to materially affect, the Trust's internal control over financial reporting.

Item 9B. *Other Information*

None.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance*

(a) *Directors, Officers and Committees.* The Trust has no directors, executive officers, audit committee, audit committee financial expert, compensation committee or nominating committee. The Trustee is a corporate Trustee which may be removed, with or without cause, by the affirmative vote of the holders of a majority of all the units then outstanding.

(b) *Section 16(a) Beneficial Ownership Reporting Compliance.* Section 16(a) of the Securities Exchange Act of 1934 requires that directors, officers, and beneficial owners of more than 10% of the registrant's equity securities file initial reports of beneficial ownership and reports of changes in beneficial ownership with the Securities and Exchange Commission and the New York Stock Exchange. To the Trustee's knowledge, based solely on the information furnished to the Trustee, the Trustee is unaware of any person that failed to file on a timely basis reports required by Section 16(a) filing requirements with respect to the Trust units of beneficial interest during and for the year ended December 31, 2018.

(c) *Code of Ethics.* Because the Trust has no employees, it does not have a code of ethics. Employees of the Trustee, Simmons Bank, must comply with the bank's code of ethics which may be found at ir.simmonsbank.com/govdocs.

Item 11. *Executive Compensation*

(a) *Compensation Committee Interlocks and Insider Participation/Compensation Committee Report.* The Trust has no officers or directors and is administered by a trustee. The Trust does not have a compensation committee or maintain any equity compensation plans and there are no units reserved for issuance under any such plans.

(b) *Compensation of the Trustee.* The Trustee and Southwest Bank, the prior trustee, received the following annual compensation for the fiscal years ended December 31, 2017 through December 31, 2018 as specified in the Trust indenture:

	2018	2017
Simmons, Trustee *(1)*	$52,261	$ —
Southwest Bank, Trustee *(1)*	17,318	67,926

(1) Under the Trust indenture, the trustee is entitled to an annual administrative fee, paid in equal monthly installments. Such fee can be adjusted annually based on an oil and gas industry index. Upon termination of the Trust, the trustee is entitled to a termination fee of $15,000.

(c) *Pay Ratio Disclosure*. The Trust does not have a principal executive officer or employees and therefore, the pay ratio disclosure is not applicable.

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

(a) *Equity Compensation Plans and Trust Repurchases.* The Trust has no equity compensation plans. The Trust has not repurchased any units during the fourth quarter of fiscal 2018.

(b) *Security Ownership of Certain Beneficial Owners.* The Trustee is not aware of any person who beneficially owns more than 5% of the outstanding units.

(c) *Security Ownership of Management.* The Trust has no directors or executive officers. The Trustee does not beneficially own any units in the Trust.

(d) *Changes in Control.* The Trustee knows of no arrangements which may subsequently result in a change in control of the Trust.

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

In computing net profits income paid to the Trust for the net profits interests, XTO Energy deducts an overhead charge for reimbursement of administrative expenses of operating the underlying properties. This charge at December 31, 2018 was approximately $938,000 per month, or $11,256,000 annually (net to the Trust of $750,400 per month or $9,004,800 annually), and is subject to annual adjustment based on an oil and gas industry index as defined in the Trust agreement.

XTO Energy sells a portion of natural gas production from the underlying properties to certain of its wholly owned subsidiaries under contracts in existence when the Trust was created, generally at amounts approximating monthly published prices. For further information, see Item 2, Properties.

See Item 11, Executive Compensation, for the remuneration received by the Trustee for the fiscal years ended December 31, 2017 through December 31, 2018.

As noted in Item 10, Directors, Executive Officers and Corporate Governance, the Trust has no directors, executive officers, audit committee, audit committee financial expert, compensation committee or nominating committee. The Trustee is a corporate trustee which may be removed, with or without cause, by the affirmative vote of the holders of a majority of all the units then outstanding.

Item 14. ***Principal Accountant Fees and Services***

Fees for services performed by PricewaterhouseCoopers LLP for the years ended December 31, 2018 and 2017 are:

	2018	2017
Audit fees-PwC	$157,000	$158,000
Audit-related fees	—	—
Tax fees	—	—
All other fees	—	—
	$157,000	$158,000

As referenced in Item 10, Directors, Executive Officers and Corporate Governance, above, the Trust has no audit committee, and as a result, has no audit committee pre-approval policy with respect to fees paid to PricewaterhouseCoopers LLP.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a) The following documents are filed as a part of this report:

1. *Financial Statements (included in Item 8 of this report)*

   Report of Independent Registered Public Accounting Firm

   Statements of Assets, Liabilities and Trust Corpus at December 31, 2018 and 2017

   Statements of Distributable Income for the years ended December 31, 2018 and 2017

   Statements of Changes in Trust Corpus for the years ended December 31, 2018 and 2017

   Notes to Financial Statements

2. *Financial Statement Schedules*

   Financial statement schedules are omitted because of the absence of conditions under which they are required or because the required information is given in the financial statements or notes thereto.

3. *Exhibits*

   (4) (a) Hugoton Royalty Trust Indenture by and between NationsBank, N.A., as Trustee, and Cross Timbers Oil Company (predecessor of XTO Energy) heretofore filed as Exhibit 4.1 to the Trust's Registration Statement No. 333-68441 on Form S-1 filed with the Securities and Exchange Commission on December 4, 1998, is incorporated herein by reference.

   (b) Net Overriding Royalty Conveyance (Hugoton Royalty Trust, 80% - Kansas) as amended and restated from Cross Timbers Oil Company (predecessor of XTO Energy) to NationsBank, N.A., as Trustee, dated December 1, 1998, heretofore filed as Exhibit 10.1.1 to the Trust's Registration Statement No. 333-68441 on Form S-1 filed with the Securities and Exchange Commission on March 16, 1999, is incorporated herein by reference.

   (c) Net Overriding Royalty Conveyance (Hugoton Royalty Trust, 80% - Oklahoma) as amended and restated from Cross Timbers Oil Company (predecessor of XTO Energy) to NationsBank, N.A., as Trustee, dated December 1, 1998, heretofore filed as Exhibit 10.2.1 to the Trust's Registration Statement No. 333-68441 on Form S-1 filed with the Securities and Exchange Commission on March 16, 1999, is incorporated herein by reference.

   (d) Net Overriding Royalty Conveyance (Hugoton Royalty Trust, 80% - Wyoming) as amended and restated from Cross Timbers Oil Company (predecessor of XTO Energy) to NationsBank, N.A., as Trustee, dated December 1, 1998, heretofore filed as Exhibit 10.3.1 to the Trust's Registration Statement No. 333-68441 on Form S-1 filed with the Securities and Exchange Commission on March 16, 1999, is incorporated herein by reference.

   (23) Consent of Miller and Lents, Ltd.

   (31) Rule 13a-14(a)/15d-14(a) Certification

   (32) Section 1350 Certification

   (99.1) Miller and Lents, Ltd. Report

Copies of the above Exhibits are available to any unitholder, at the actual cost of reproduction, upon written request to the Trustee, Simmons Bank, 2911 Turtle Creek Blvd, Suite 850, Dallas, Texas 75219.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Report to be signed on its behalf by the undersigned thereunto duly authorized.

HUGOTON ROYALTY TRUST
By SIMMONS BANK, TRUSTEE

By /S/ NANCY WILLIS
Nancy Willis
Vice President

EXXON MOBIL CORPORATION

Date: March 29, 2019

By /S/ DAVID LEVY
David Levy
Vice President – Upstream Business Services

(The Trust has no directors or executive officers.)

Form 10-K

A copy of the Hugoton Royalty Trust Form 10-K has been provided with this Annual Report. Additional copies of this Annual Report and Form 10-K will be provided to unitholders without charge upon request. Copies of exhibits to the Form 10-K may be obtained upon request or from the Trust's web site at www.hgt-hugoton.com.

Hugoton Royalty Trust

Simmons Bank, Trustee
2911 Turtle Creek Blvd, Ste 850
Dallas, TX 75219

Attention: Annual Reports

1-855-588-7839

Web site

www.hgt-hugoton.com

Auditors

PricewaterhouseCoopers LLP
Dallas, Texas

Legal and Tax Counsel

Thompson & Knight LLP
Dallas, Texas

Transfer Agent and Registrar

American Stock Transfer and Trust Company LLC
www.astfinancial.com

Certification

The Trustee's certification, required by Section 302 of the Sarbanes-Oxley Act of 2002, has been filed as Exhibit 31 of the Trust's Form 10-K, for the fiscal year ended December 31, 2018.

Hugoton Royalty Trust
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