

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, 2023

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

*(State or other jurisdiction of
incorporation or organization)*

58-6379215

*(I.R.S. Employer
Identification No.)*

c/o Corporate Trustee:

Argent Trust Company

3838 Oak Lawn Ave, Suite 1720

Dallas, Texas 75219-4518

(Address of principal executive offices)

75219

(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:

Title of each class	Trading symbol	Name of each exchange on which registered
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Units of Beneficial Interest	HGTXU	OTCQB
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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 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 ☐

Non-accelerated filer ☒

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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☐

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

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, 2023 (the last business day of the registrant's most recently completed second fiscal quarter) was approximately \$36.0 million.

The number of units of beneficial interest outstanding as of March 13, 2024, was 40,000,000.

HUGOTON ROYALTY TRUST
2023 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:

<i>Bbl</i>	Barrel (of oil)
<i>Bcf</i>	Billion cubic feet (of natural gas)
<i>BOE</i>	Barrel of oil equivalent
<i>Mcf</i>	Thousand cubic feet (of natural gas)
<i>MMBtu</i>	One million British Thermal Units, a common energy measurement
<i>net proceeds</i>	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.
<i>net profits income</i>	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 income tax purposes.
<i>net profits interest</i>	<p>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:</p> <p><i>80% net profits interests</i> - interests that entitle the Trust to receive 80% of the net proceeds from the underlying properties.</p>
<i>underlying properties</i>	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.
<i>working interest</i>	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 and, hereafter, “XTO Energy”), as grantor, and NationsBank, N.A., as Trustee. The current trustee of the Trust is Argent Trust Company, a Tennessee chartered trust company (“Argent”). Effective April 10, 2023, Simmons Bank resigned as trustee, and Argent was appointed as the successor trustee.

The defined term “Trustee” as used herein shall refer to Simmons Bank for periods from February 20, 2018, through April 9, 2023, and shall refer to Argent for periods on and after April 10, 2023.

The principal office of the Trust is 3838 Oak Lawn Ave, Suite 1720, Dallas, Texas 75219. (Telephone number 855-588-7839). The Trust’s internet website is www.hgt-hugoton.com. We make available free of charge, through our website, 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 website 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 “HGT XU.” The Trust transitioned from the OTCQX to the OTCQB on May 19, 2020.

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.

The majority of previous net profits income received by the Trust has been attributable to natural gas. 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.

All three of the Trust's conveyances are in excess costs resulting in no net proceeds to the Trust and a reduction in the Trust's expense reserve, which have resulted in no unitholder distributions since July 2023. These conditions raise substantial doubt about the Trust's ability to continue as a going concern as the Trust does not have 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 or alternatives to the Trust continuing as a going concern. If the Trust is unable to continue as a going concern, unitholders could incur significant losses on their investment in the Trust or lose their entire investment in the Trust altogether. For further information see Item 7. *Trustee's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources*.

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 has historically been tied to the recent and expected levels of cash distributions on the Trust units. However, no cash distribution has occurred for eight months as of the date of this report, April 1, 2024. 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 or that distributions from the Trust will resume in 2024 or at all.

Current and future 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 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, trade barriers, political instability, public health concerns, 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, environmental regulations, production restrictions, or trade barriers, can affect product prices. Oil and natural gas prices fluctuated widely over the recent past and may vary significantly from period to period. Further, a significant decline in current oil or natural gas prices or lower anticipated long-term 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. Adjustments impacting volume or value could also impact the reported natural gas and oil prices. 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 has been the case with respect to the properties underlying all three of the Trust's conveyances for the eight months preceding the date of this report), 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 approximately \$3 million for 2024 which could exceed revenues for the underlying conveyances. See Item 2. *Properties*.

As described in Note 8 – Contingencies to the Notes to Financial Statements, XTO Energy 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, the final plan of allocation was approved by the court. Based on the final plan of allocation, XTO Energy 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 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. The Trust and XTO Energy conducted the interim hearing on the claims related to the *Chieftain* settlement on October 12-13, 2020. In the arbitration, the Trustee contended that the approximately \$24.3 million allocation related to the *Chieftain* settlement was not a production cost and, therefore, there should not be a related adjustment to the Trust's share of net proceeds. However, XTO Energy contended that the approximately \$24.3 million was a production cost and should reduce the Trust's share of net proceeds.

On January 20, 2021, the arbitration panel issued its Corrected Interim Final Award (i) "reject[ing] the Trust's contention that XTO has no right under the Conveyance to charge the Trust with amounts XTO paid under section 1.18(a)(i) as royalty obligations to settle the *Chieftain* litigation" and (ii) stating "[t]he next phase will determine how much of the *Chieftain* settlement can be so charged, if any of it can be, in the exercise of the right found by the Panel." Following briefing by both parties, on May 18, 2021, the Panel issued its second interim final award over the amount of XTO Energy's settlement in the *Chieftain* class action lawsuit that can be charged to the Trust as a production cost. The Panel in its decision has ruled that out of the \$80 million settlement, the "Trust is obligated to pay its share under the Conveyance of the \$48 million that was received by the plaintiffs in the *Chieftain* lawsuit by virtue of the settlement of that litigation. The Trust is not obligated by the Conveyance to pay any share of the \$32 million received by the lawyers for the plaintiffs in the *Chieftain* lawsuit by virtue of the settlement." XTO Energy and the Trustee are in the process of determining the portion of the \$48 million that is allocable to Trust properties to be charged as an excess cost to the Trust, but estimate it to be approximately \$14.6 million net to the Trust.

The reduction in the Trust's share of net proceeds from the portion of the settlement amount the Panel has ruled may be charged against the Oklahoma conveyance would result in excess costs under the Oklahoma conveyance that would likely result in no distributions under the Oklahoma conveyance while these excess costs are recovered. This award completes the portion of the arbitration related to the *Chieftain* settlement. Excess costs on any individual conveyance would not affect net proceeds to the Trust on any of the other remaining conveyances.

Other Trustee claims related to disputed amounts on the computation of the Trust's net proceeds for 2014 through 2019 and 2021 were bifurcated from the initial arbitration. Although the arbitration is not terminated, the

final hearing regarding the remaining dispute over net proceeds, previously scheduled to occur on November 8, 2023, was cancelled. XTO Energy and the Trustee will provide material updates as they become available. See Item 8. *Financial Statements and Supplementary Data* – Notes to Financial Statements – Note 8 – Contingencies for additional information.

Government action, policies or regulations designed to discourage production, reduce demand for, or promote alternatives to oil and natural gas could impact the price of oil and natural gas produced on the properties underlying the Trust's net profits interests, directly as intended or through unintended consequences.

Governments around the world are considering actions intended to reduce greenhouse gas emissions by decreasing both the supply of and the demand for oil and natural gas products or promote alternatives. These include the adoption of cap-and-trade regimes, carbon taxes, trade tariffs, minimum renewable usage requirements, restrictive permitting, increased mileage and other efficiency standards, mandates for sales of electric vehicles, mandates for use of specific fuels or technologies, and other incentives or mandates designed to support transitioning to lower-emission energy sources. Political and other actors and their agents also increasingly seek to advance climate change objectives indirectly, such as by seeking to reduce the availability or increase the cost of financing and investment in the oil and gas sector. Depending on how policies are formulated and applied, such policies could impact the ability and costs of the operators of the properties underlying the Trust's net profits interests to supply products, demand for their products, or the competitiveness of hydrocarbon-based products, which in turn, could reduce net proceeds to the Trust. Any policy that increases the costs for operators of the properties underlying the net profits interests or lower market prices could have a material impact on the distributable income of the Trust.

War, terrorism, geopolitical hostilities, and other military actions or political instability could adversely affect Trust distributions or the market price of the Trust units.

There are a number of national and international events that could cause instability in global financial and energy markets. War, terrorist attacks and the threat of war or terrorist attacks, whether domestic or foreign, as well as other military or similar actions taken in response, impact the demand for and price of oil and natural gas in unpredictable ways, including increasing volatility in pricing. Actual or threatened acts of war, 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 such an event.

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 "HGT XU." The Trustee received notice from the OTC Markets Group Inc. dated April 16, 2020, notifying the Trustee that the Trust was no longer in compliance with Section 3.2(a) of the Standards for Continued Qualification of the OTCQX Rules for U.S. Companies, in that as of December 31, 2019, the Trust had less than \$2 million in net tangible assets, average revenue of less than \$6 million over the past three years, and the Trust's bid price is below \$5 per share. The notice stated that if the Trust was unable to cure the deficiency by May 18, 2020, then it would be moved from OTCQX to the OTC Pink market. The Trust transitioned from the OTCQX to the OTCQB on May 19, 2020. Trading on the OTC 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 the 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. No assurance can be made how such transition may affect the liquidity of the units.

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.

The Trust may be subject to attempted cybersecurity disruptions from a variety of sources including state-sponsored actors.

XTO Energy's defensive preparedness includes multi-layered technological capabilities designed to prevent and detect cybersecurity disruptions; non-technological measures such as threat information sharing with governmental and industry groups; internal training and awareness campaigns including routine testing of employee awareness and business preparedness for response and recovery. The Trustee also maintains robust cybersecurity protocols including, but not limited to, technological capabilities that prevent and detect disruptions; computer workstations and programs protected with passwords and passphrases, as well as employee training throughout the year on banking regulations and cybersecurity followed up by testing of that knowledge. Other, non-technical protocols include securing of documents and work areas that could contain personal, non-public information. If the measures taken to protect against cybersecurity disruptions prove to be insufficient or if proprietary data is otherwise not protected, XTO Energy, the Trustee or customers, employees, or third parties could be adversely affected. The Trust has limited ability to influence third parties, including our partners, suppliers, and service providers (including providers of cloud-hosting services for our data or applications), to implement strong cybersecurity controls and is exposed to potential harm from cybersecurity events that may affect their operations. Cybersecurity disruptions could cause physical harm to people or the environment; damage or destroy assets; compromise business systems; result in proprietary information being altered, lost, or stolen; result in employee, customer, or third-party information being compromised; or otherwise disrupt our business operations. We could incur significant costs to remedy the effects of a major cybersecurity disruption in addition to costs in connection with resulting regulatory actions, litigation, or reputational harm.

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 of 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 interests will cease to produce in commercial quantities and the Trust will, therefore, cease to receive any net proceeds therefrom.

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, Trust unitholders will realize gain or loss equal to the difference between the amount realized on the sale and termination of the Trust and their 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. Trust unitholders should consult their own tax advisor regarding all Trust tax compliance matters.

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 ("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 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, natural disasters or public health events; and
8. costs of, or shortages or delays in the availability of, drilling rigs, labor, 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. These regulations can often be changed by administrative agencies without formal legislation, resulting in additional costs that can impact distributions. 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 (“TCJA”) was enacted December 22, 2017, and made 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 Trust unitholders should consult their tax advisor regarding the TCJA and its effect on an investment in Trust units. In addition, the current administration has generally proposed repealing fossil fuel tax subsidies, which could impact certain tax benefits available to Trust unitholders.

Any modification to the U.S. federal income tax laws or interpretations thereof 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, 2023, the Trust did not have any unresolved Securities and Exchange Commission staff comments.

ITEM 1C. CYBERSECURITY

The Trust does not have a board of directors; therefore, the Trustee is responsible for oversight of the Trust’s risks from cybersecurity threats. The Trustee has dedicated personnel that are responsible for assessing and managing the Trust’s cyber risk management program, informing senior management of the Trustee regarding the prevention, detection, mitigation, and remediation of cybersecurity incidents and supervising such efforts. The Trustee’s information technology team has decades of experience selecting, deploying, and operating cybersecurity technologies, initiatives, and processes, and relies on threat intelligence as well as other information obtained from governmental, public or private sources, including external consultants engaged by the Trustee to monitor the prevention, detection, mitigation, and remediation of cybersecurity incidents. External partners are a key part of the Trustee’s cybersecurity protocols and policies. The Trustee works with leading firms in the cybersecurity industry, leveraging their technology and expertise to monitor and maintain the performance and effectiveness of products and services that are used by the Trustee.

The Trustee maintains a cyber risk management program designed to identify, assess, manage, mitigate, and respond to cybersecurity threats, which processes are integrated into the Trustee’s overall risk management process. The Trustee maintains robust cybersecurity protocols including, but not limited to technological capabilities that prevent and detect disruptions; computer workstations and programs protected with passwords and passphrases, as well as employee training throughout the year on financial regulations and cybersecurity followed up by testing of that knowledge. The protocols are based on recognized best practices and standards for cybersecurity and information technology. The Trustee has an annual assessment, performed by a third-party vendor, of the Trustee’s cyber risk management program.

Other, non-technical protocols include securing of documents and work areas that could contain personal, non-public information and independent verification of information changes by outside vendors.

The Trust faces risks from cybersecurity threats that could have a material adverse effect on its business, financial condition, results of operations, cash flows or reputation. The Trustee has experienced, and will continue to experience, cyber incidents in the normal course of its business. However, prior cybersecurity incidents have not had a material adverse effect on the Trust’s business, financial condition, results of operations, or cash flows. See Item 1A. *Risk Factors – The Trust may be subject to attempted cybersecurity disruptions from a variety of sources including state-sponsored actors.*

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 one percent 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, 2023, is approximately 10 years. This index is calculated using total proved reserves and estimated 2024 production for the underlying properties. The projected 2024 production is from proved developed producing reserves as of December 31, 2023. 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 55 percent natural gas and 45 percent oil. XTO Energy operates approximately 95 percent 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 Item 7. *Trustee's Discussion and Analysis of Financial Condition and Results of Operations*. Total 2023 development costs deducted for the underlying properties were \$9.5 million, an increase of \$7.1 million from the prior year. XTO Energy has informed the Trustee that total 2024 budgeted development costs for the underlying properties are approximately \$3 million. Changes in oil or natural gas prices could impact future development plans on the underlying properties.

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 2023, daily sales volumes from the underlying properties in the Hugoton area averaged approximately 5,600 Mcf of gas and 30 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 new wells or perform any workovers in 2023. XTO Energy has informed the Trustee that it does not plan to drill any new wells or perform any workovers during 2024.

XTO Energy's future development plans for the underlying properties in the Hugoton area may 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. XTO Energy has advised the Trustee that the system collects approximately 7,000 Mcf per day, of which the majority of its throughput is from underlying properties. 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 an ExxonMobil affiliate 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. has passed its primary term date of March 31, 2019, and is currently being renewed annually on an evergreen basis, and can be 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 approximately 12,200 Mcf of gas and 550 Bbls of oil in 2023.

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 performed one workover in 2023. XTO Energy has informed the Trustee that it does not plan to drill any new wells or perform any workovers in Major County during 2024.

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 or perform any workovers in 2023. XTO Energy has informed the Trustee that it does not plan to drill any new wells or perform any workovers in Woodward County during 2024.

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 performed one workover in 2023. XTO Energy has informed the Trustee that it does not plan to drill any new wells or perform any workovers within the Elk City field during 2024.

XTO Energy's future development plans for the underlying properties in the Anadarko Basin may include:

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 percent 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. As of December 31, 2023, the gathering system was collecting approximately 5,800 Mcf per day, approximately 65 percent of which are operated by XTO Energy. Estimated capacity of the gathering system is 21,000 Mcf per day. The gathering subsidiary also provides contract operating services to properties in Woodward County, collecting approximately 2,050 Mcf per day, for an average fee of approximately \$0.48 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 2023 sales volumes from the underlying properties in the Fontenelle field averaged approximately 8,000 Mcf of natural gas and 20 Bbls of oil. XTO Energy did not drill any wells or perform any workovers in the Green River Basin in 2023. 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 2024. 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.

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 2023, the fuel charge was approximately one percent of the volumes produced and the fee was approximately \$0.14 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 \$0.13 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 percent 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, 2023. Undeveloped acreage is not significant.

	<u>Gross</u>	<u>Net</u>
Hugoton Area	201,032	189,142
Anadarko Basin	151,699	119,400
Green River Basin	35,862	28,151
Total	<u>388,593</u>	<u>336,693</u>

The following is a summary of the producing wells on the underlying properties as of December 31, 2023:

	Operated Wells		Non-Operated Wells		Total (a)	
	Gross	Net	Gross	Net	Gross	Net
Gas	987.0	883.8	192.0	43.6	1,179.0	927.4
Oil	36.0	33.9	28.0	3.9	64.0	37.8
Total	<u>1,023.0</u>	<u>917.7</u>	<u>220.0</u>	<u>47.5</u>	<u>1,243.0</u>	<u>965.2</u>

- (a) During 2023, 2022, and 2021 there were no exploratory wells drilled on the underlying properties. There were no dry wells drilled in 2023 and 2021 and there was one gross (0.01 net) non-operated dry well drilled in 2022. There were three gross (1.53 net), one gross (0.35 net), and one gross (0.67 net) developmental wells drilled in 2023, 2022, and 2021, respectively. Not included in the total is one gross (0.22 net) non-operated well in progress of drilling at December 31, 2023.

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, 2023:

	Underlying Properties		Net Profits Interests			
	Proved Reserves (a)		Proved Reserves (a) (b)		Future Net Cash Flows from Proved Reserves (a) (c)	
	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Undiscounted	Discounted
<i>(in thousands)</i>						
Oklahoma	56,325	1,318	7,329	171	\$27,056	\$19,012
Wyoming	17,772	21	—	—	—	—
Kansas	4,925	95	—	—	—	—
Total	<u>79,022</u>	<u>1,434</u>	<u>7,329</u>	<u>171</u>	<u>\$27,056</u>	<u>\$19,012</u>

- (a) Based on 12-month average oil price of \$75.88 per Bbl and \$2.59 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 percent.

Proved reserves at December 31, 2023, consist of the following:

	Underlying Properties		Net Profits Interests	
	Proved Reserves		Proved Reserves	
	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)
<i>(in thousands)</i>				
Proved developed producing reserves	79,022	1,434	7,329	171
Proved undeveloped reserves	—	—	—	—
Proved developed non-producing reserves	—	—	—	—
Total proved reserves	<u>79,022</u>	<u>1,434</u>	<u>7,329</u>	<u>171</u>

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, 2023. Miller and Lents' primary technical person responsible for calculating the Trust's reserves has more than 12 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 three years ended December 31 were as follows:

	2023	2022	2021
Production			
<i>Underlying Properties</i>			
Gas – Sales (Mcf)	9,397,772	9,771,977	10,193,158
Average per day (Mcf)	25,747	26,773	27,926
Oil – Sales (Bbls)	217,440	245,586	232,576
Average per day (Bbls)	596	673	637
<i>Net Profits Interests</i>			
Gas – Sales (Mcf)	990,526	2,440,780	—
Average per day (Mcf)	2,714	6,687	—
Oil – Sales (Bbls)	11,205	48,829	—
Average per day (Bbls)	31	134	—
Average Sales Price			
Gas (per Mcf)	\$ 5.18	\$ 7.08	\$ 4.05
Oil (per Bbl)	\$ 75.88	\$ 83.91	\$ 59.25
Average Production			
Cost per BOE	\$ 18.36	\$ 16.16	\$ 13.37

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

Conveyance	Underlying Gas Production (Mcf)		
	2023	2022	2021
Oklahoma	5,845,567	5,833,016	6,002,087
Wyoming	2,921,925	3,249,822	3,480,757
Kansas	630,280	689,139	710,314
Total	9,397,772	9,771,977	10,193,158

Conveyance	Underlying Oil Production (Bbls)		
	2023	2022	2021
Oklahoma	201,461	181,577	220,964
Wyoming	6,267	7,169	7,789
Kansas	9,712	56,840	3,823
Total	217,440	245,586	232,576

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 the life of the lease. 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 two percent 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 ("FERC"). 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) ("EISA"). 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 allowable 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. Impairments recorded 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, unitholders are taxed directly on their 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. The Trust also incurs administration expenses and may earn interest income on funds held for distribution and on 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 the gross income from such net profits interest, limited to 100 percent of the net income from such net profits interests. 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 their 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 Section 1254 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.

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 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 percent, 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 percent. Under the TCJA, for such tax years, personal exemptions and miscellaneous itemized deductions are not allowed. Further, the U.S. federal income tax rate applicable to corporations is 21 percent, and such rate applies to both ordinary income and capital gains.

Section 1411 of the Code imposes a 3.8 percent 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 net profits 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, and after December 31, 2025, 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 two 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 advisor 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. Argent Trust Company, EIN: 62-1437218, 3838 Oak Lawn Ave, Suite 1720, 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 advisor 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. The Trust did not file a Kansas income tax return for the 2015 through 2021 tax years due to the fact that there were no revenues, income, or deductions attributable to properties located in Kansas in that time period.

Wyoming does not impose a state income tax.

Unitholders should consult their 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

As previously disclosed, XTO Energy advised the Trustee that it reached a settlement with the plaintiffs in the *Chieftain* class action royalty case. On July 27, 2018, the final plan of allocation was approved by the court. Based on the final plan of allocation, XTO Energy 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 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. The Trust and XTO Energy conducted the interim hearing on the claims related to the *Chieftain* settlement on October 12-13, 2020. In the arbitration, the Trustee contended that the approximately \$24.3 million allocation related to the *Chieftain* settlement was not a production cost and, therefore, there should not be a related adjustment to the Trust's share of net proceeds. However, XTO Energy contended that the approximately \$24.3 million was a production cost and should reduce the Trust's share of net proceeds.

On January 20, 2021, the arbitration panel issued its Corrected Interim Final Award (i) "reject[ing] the Trust's contention that XTO has no right under the Conveyance to charge the Trust with amounts XTO paid under section 1.18(a)(i) as royalty obligations to settle the *Chieftain* litigation" and (ii) stating "[t]he next phase will

determine how much of the *Chieftain* settlement can be so charged, if any of it can be, in the exercise of the right found by the Panel.” Following briefing by both parties, on May 18, 2021, the Panel issued its second interim final award over the amount of XTO Energy’s settlement in the *Chieftain* class action lawsuit that can be charged to the Trust as a production cost. The Panel in its decision has ruled that out of the \$80 million settlement, the “Trust is obligated to pay its share under the Conveyance of the \$48 million that was received by the plaintiffs in the *Chieftain* lawsuit by virtue of the settlement of that litigation. The Trust is not obligated by the Conveyance to pay any share of the \$32 million received by the lawyers for the plaintiffs in the *Chieftain* lawsuit by virtue of the settlement.” XTO Energy and the Trustee are in the process of determining the portion of the \$48 million that is allocable to Trust properties to be charged as an excess cost to the Trust but estimate it to be approximately \$14.6 million net to the Trust.

The reduction in the Trust’s share of net proceeds from the portion of the settlement amount the Panel has ruled may be charged against the Oklahoma conveyance would result in excess costs under the Oklahoma conveyance that would likely result in no distributions under the Oklahoma conveyance while these excess costs are recovered. This award completes the portion of the arbitration related to the *Chieftain* settlement. Excess costs on any individual conveyance would not affect net proceeds to the Trust on any of the other remaining conveyances.

Other Trustee claims related to disputed amounts on the computation of the Trust’s net proceeds for 2014 through 2019 and 2021 were bifurcated from the initial arbitration. Although the arbitration is not terminated, the final hearing regarding the remaining dispute over net proceeds, previously scheduled to occur on November 8, 2023, was cancelled. XTO Energy and the Trustee will provide material updates as they become available.

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, based on the information available at this stage of the various proceedings, 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 “HGT XU.” The Trust transitioned from the OTCQX to the OTCQB on May 19, 2020. Any quotations on the OTCQB reflect inter-dealer prices, without retail mark-up, mark-down, or commission and may not necessarily reflect actual transactions.

At March 19, 2024, there were 40,000,000 units outstanding and approximately 516 unitholders of record; 39,630,379 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. [RESERVED]

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)	
	2023	2022	2023	2022
Sales Volumes				
Gas (Mcf) (b)				
Underlying properties	9,397,772	9,771,977	2,465,801	2,486,247
Average per day	25,747	26,773	26,802	27,024
Net profits interests	990,526	2,440,780	—	1,007,610
Oil (Bbls) (b)				
Underlying properties	217,440	245,586	95,885	45,584
Average per day	596	673	1,042	495
Net profits interests	11,205	48,829	—	19,700
Average Sales Prices				
Gas (per Mcf)	\$ 5.18	\$ 7.08	\$ 3.37	\$ 7.53
Oil (per Bbl)	\$ 75.88	\$ 83.91	\$ 77.16	\$ 87.51
Revenues				
Gas sales	\$48,663,530	\$69,197,629	\$ 8,302,933	\$18,723,053
Oil sales	16,498,624	20,607,491	7,398,667	3,988,840
Total Revenues	65,162,154	89,805,120	15,701,600	22,711,893
Costs				
Taxes, transportation and other	12,224,150	13,169,884	2,573,696	3,799,727
Production expense	19,727,285	17,692,775	5,178,180	4,981,516
Development costs	9,460,301	2,390,390	205,602	970,974
Overhead	13,025,797	12,587,189	3,373,745	3,084,904
Excess costs (c)	(3,610,271)	19,534,417	4,370,377	—
Total Costs	50,827,262	65,374,655	15,701,600	12,837,121
Other Proceeds	—	32	—	—
Net Proceeds	14,334,892	24,430,497	—	9,874,772
Net Profits Percentage	80%	80%	80%	80%
Net Profits Income	<u>\$11,467,914</u>	<u>\$19,544,398</u>	<u>\$ —</u>	<u>\$ 7,899,818</u>

- (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 12 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 4 to Financial Statements under Item 8. *Financial Statements and Supplementary Data*.

Results of Operations

Years Ended December 31, 2023 and 2022

Net profits income for 2023 was \$11,467,914, as compared with \$19,544,398 for 2022. This was primarily the result of lower oil and gas prices (\$16.5 million), increased development costs (\$5.7 million), decreased oil and gas production (\$3.3 million), increased production expenses (\$1.6 million), and increased overhead (\$0.3 million), partially offset by net excess costs activity (\$18.5 million) and decreased taxes, transportation and other costs (\$0.8 million).

Trust administration expense was \$1,093,016 in 2023 as compared to \$758,312 in 2022. Cash reserve activity was (\$655,952) in 2023 and \$1,000,000 in 2022. Cash reserve activity for 2023 included utilization of \$655,952 for the payment of trust expenses. Cash reserve activity for 2022 included additions of \$1,000,000 which the Trustee reserved for administrative expenses. Interest income was \$65,670 in 2023 and \$16,810 in 2022. Changes in interest income are attributable to fluctuations in net profits income, cash reserve and interest rates. Distributable income was \$11,096,520 or \$0.277413 per unit in 2023 and \$16,585,039 or \$0.414626 per unit in 2022.

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. Underlying gas sales volumes decreased 4 percent from 2022 to 2023 primarily because of natural production decline and timing of cash receipts, partially offset by gas sales from new wells in Major County, Oklahoma.

Oil. Underlying oil sales volumes decreased 11 percent from 2022 to 2023 primarily because of natural production decline and timing of cash receipts, partially offset by oil sales from new wells in Major County, Oklahoma.

The estimated rate of natural production decline on the underlying oil and gas properties is approximately six to eight percent a year.

Prices

Gas. The 2023 average gas price was \$5.18 per Mcf, down 27 percent from the 2022 average gas price of \$7.08 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 export levels of liquefied natural gas. Natural gas prices are expected to remain volatile. The average NYMEX price for November 2023 through January 2024 was \$2.83 per MMBtu. At March 15, 2024, the average NYMEX gas price for the following 12 months was \$2.70 per MMBtu.

Oil. The average oil price for 2023 was \$75.88 per Bbl, down 10 percent from the average oil price for 2022 of \$83.91 per Bbl. Oil prices are expected to remain volatile. The average NYMEX price for November 2023 through January 2024 was \$74.50 per Bbl. At March 15, 2024, the average NYMEX oil price for the following 12 months was \$77.89 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 costs generally fluctuate with changes in total revenues. Taxes, transportation and other costs decreased 7 percent from 2022 to 2023 primarily because of decreased gas production taxes and gas deductions due to lower revenues, partially offset absence of Oklahoma production tax refunds.

Production expense. Production expense increased 11 percent from 2022 to 2023 primarily because of increased labor, plug and abandonment expenses, pipeline costs, and repairs and maintenance, partially offset by decreased power and fuel and salt water disposal costs.

Development costs. Development costs increased \$7.1 million from 2022 to 2023 primarily because of timing of drilling costs related to non-operated wells in Major County, Oklahoma. Changes in oil or natural gas prices could impact future development plans on the underlying properties.

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 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, including the balance and accrued interest by conveyance, see Note 4 to Financial Statements under Item 8. *Financial Statements and Supplementary Data*.

Fourth Quarter 2023 and 2022

Net profits income for fourth quarter 2023 was \$0 as compared with \$7,899,818 for fourth quarter 2022. This was primarily the result of lower oil and gas prices (\$8.7 million), net excess costs activity (\$3.5 million), increased overhead (\$0.2 million), and increased production expenses (\$0.2 million), offset by increased oil production (\$3.1 million), decreased taxes, transportation and other costs (\$1.0 million), and decreased development costs (\$0.6 million).

After adding interest income of \$8,212, deducting administration expense of \$302,627 and utilizing \$294,415 of the cash reserve for the payment of trust expenses, distributable income for fourth quarter 2023 was \$0 or \$0.000000 per unit. Distributable income for fourth quarter 2022 was \$7,620,680 or \$0.190517 per unit.

Distributions to unitholders for the quarter ended December 31, 2023, were:

Record Date	Payment Date	Per Unit
October 31, 2023	November 14, 2023	\$0.000000
November 30, 2023	December 14, 2023	0.000000
December 29, 2023	January 16, 2024	0.000000
		<u>\$0.000000</u>

Volumes

Fourth quarter underlying gas sales volumes decreased 1 percent primarily because of natural production decline and timing of cash receipts, partially offset by gas sales from new wells in Major County, Oklahoma. Underlying oil sales increased 110 percent primarily due to oil sales from new wells in Major County, Oklahoma, partially offset by natural production decline and timing of cash receipts.

Prices

The average fourth quarter 2023 gas price was \$3.37 per Mcf, down 55 percent from the fourth quarter 2022 average price of \$7.53 per Mcf. The average fourth quarter 2023 oil price was \$77.16 per Bbl, down 12 percent from the fourth quarter 2022 average price of \$87.51 per Bbl. For further information about product prices, see “Years Ended December 31, 2023 and 2022 – Prices” above.

Costs

Taxes, transportation and other. Taxes, transportation and other costs decreased 32 percent for the fourth quarter primarily because of decreased production taxes and gas deductions due to lower gas revenues.

Production expense. Fourth quarter production expense increased 4 percent primarily because of increased plug and abandonment expenses, labor, and pipeline costs, partially offset by decreased repairs and maintenance expenses and field costs.

Development costs. Development costs decreased 79 percent for the fourth quarter primarily because of timing of drilling costs related to non-operated wells in Major County, Oklahoma.

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 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 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. Accumulated excess costs for the Kansas, Oklahoma and Wyoming conveyances have resulted in insufficient net proceeds to the Trust 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 does not have sufficient cash to meet its obligations during the one-year period after the dates that the financial statements are issued. Factors attributable to the cash shortage are primarily the previously disclosed development costs to drill three non-operated wells in Major County, Oklahoma, lower oil and natural gas prices during 2023, and excess cost positions on the Kansas, Oklahoma and Wyoming conveyances including accumulated interest, which have resulted in no unitholder distributions since July 2023. In addition, on May 18,

2021, the arbitration panel issued its second interim final award over the amount of XTO Energy's settlement in the *Chieftain* class action lawsuit that can be charged to the Trust as a production cost which XTO Energy has estimated to be approximately \$14.6 million net to the Trust. This adjustment would further increase excess costs on the Oklahoma conveyance. The Trustee has prepared a preliminary budget estimating the administrative expenses for the year ending December 31, 2024, and the three months ending March 31, 2025, which assumes no cash inflow from either net profits income or from other sources. The Trustee intends to review options for the Trust which may include alternatives to continuing as a going concern or may include seeking financing to pay the Trust obligations during the one-year period after the date the financial statements are issued; however, there can be no assurance that financing will be available on acceptable terms or at all. If financing became available to the Trust, it would have to be repaid, together with interest, and the Trust's expense reserve would have to be replenished prior to any distributions to unitholders.

On July 9, 2020, the Trustee notified XTO Energy of the Trustee's claim to indemnification to the Trust Estate for all liability, expense, claims, damages or loss incurred by the Trustee in connection with the administration of the Trust. The Trustee stated it anticipates seeking reimbursement from XTO Energy upon depletion of the Trust's cash reserve. XTO Energy responded that any indemnity claim to XTO Energy is premature before the Trust Estate is exhausted.

The Trust's financial statements do not include any adjustments that might result from the outcome of these uncertainties.

Greenhouse Gas Emissions and Climate Change Regulations

There is an increased focus by local, national and international regulatory bodies on greenhouse gas ("GHG") emissions and climate change. A number of nations and U.S. states have adopted or are considering some form of climate change legislation and regulations, including carbon taxes, cap-and-trade policies and bans on drilling in certain areas or in certain ways. 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 or a ban of certain types of activities in order to comply with climate change or GHG emissions legislation, which costs could reduce or eliminate 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.

Related Party Transactions

XTO Energy operates approximately 95 percent 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, 2023, the monthly overhead charge, based on the number of operated wells, was approximately \$1,060,000 (\$848,000 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 and an ExxonMobil affiliate purchases NGLs for a price

based upon third-party sales. 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 \$4.1 million for 2023, or 8 percent of total gas sales, \$6.1 million for 2022, or 9 percent of total gas sales.

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.

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 percent 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, excess costs, reserve-to-production ratios, future production, development activities and associated operating expenses, future development plans by area, increased density drilling, maintenance projects, development, production, regulatory and other costs, oil and gas prices and expectations for future demand, the impact of inflation and economic downturns on economic activity, government policy and its impact on oil and gas prices and future demand, the development and competitiveness of alternative energy sources, pricing differentials, proved reserves, future net cash flows, production levels, expense reserve budgets, availability of financing, arbitration, litigation, liquidity, financing, political and regulatory matters, such as tax and environmental policy, climate policy, trade barriers, sanctions, competition, war and other political or security disturbances. 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 "may," "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

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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 Argent Trust Company, 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, 2023 and 2022, and the related statements of distributable income and 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, 2023 and 2022, 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, accumulated excess costs have resulted in insufficient net proceeds available to the Trust and a reduction in the Trust's expense reserve that 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 Trustee. 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 the Trustee, 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.

Critical Audit Matters

Critical audit matters are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that (i) relate to accounts or disclosures that are material to the financial statements and (ii) involved our especially challenging, subjective, or complex judgments. We determined there are no critical audit matters.

/s/ PricewaterhouseCoopers LLP
Dallas, Texas
April 1, 2024

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

HUGOTON ROYALTY TRUST

STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

	December 31	
	2023	2022
Assets		
Cash and short-term investments	\$344,048	\$2,829,458
Interest to be received	—	4,902
Net profits interests in oil and gas properties – net (Notes 1 and 2)	—	—
	<u>\$344,048</u>	<u>\$2,834,360</u>
Liabilities and Trust Corpus		
Distribution payable to unitholders	\$ —	\$1,834,360
Expense reserve (a)	344,048	1,000,000
Trust corpus (40,000,000 units of beneficial interest authorized and outstanding)	—	—
	<u>\$344,048</u>	<u>\$2,834,360</u>

(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	
	2023	2022
Net profits income	\$11,467,914	\$19,544,398
Interest income	65,670	16,810
Total income	11,533,584	19,561,208
Administration expense	1,093,016	758,312
Cash reserves withheld (used) for Trust expenses	(655,952)	1,000,000
Change in accounts payable to the Trustee (increase)/decrease	—	1,217,857
Distributable income	<u>\$11,096,520</u>	<u>\$16,585,039</u>
Distributable income per unit (40,000,000 units)	<u>\$ 0.277413</u>	<u>\$ 0.414626</u>

STATEMENTS OF CHANGES IN TRUST CORPUS

	Year Ended December 31	
	2023	2022
Trust corpus, beginning of year	\$ —	\$ (1,217,857)
Distributable income	11,096,520	16,585,039
Distributions declared	(11,096,520)	(16,585,039)
Change in accounts payable to the Trustee (increase)/decrease	—	1,217,857
Trust corpus, end of year	<u>\$ —</u>	<u>\$ —</u>

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” and, hereafter, “XTO Energy”). 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).

Effective April 10, 2023, Argent Trust Company (“Argent”) became the Trustee of the Trust. References herein to the Trustee for periods prior to April 10, 2023, shall refer to Simmons Bank, the former Trustee of 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 one percent 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).

Hugoton Royalty Trust
NOTES TO FINANCIAL STATEMENTS—(Continued)

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.

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. During the third quarter 2019, the carrying value of the NPI was written down to its fair value of zero, resulting in an impairment of \$15,681,533 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 \$174,078,891 as of September 30, 2019, when the NPI was written down to its fair value of zero.

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. Accumulated excess costs for the Kansas, Oklahoma and Wyoming conveyances have resulted in insufficient net proceeds to the Trust 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 does not have sufficient cash to meet its obligations during the one-year period after the dates that the financial statements are issued. Factors attributable to the cash shortage are primarily the previously disclosed development costs to drill three non-operated wells in Major County, Oklahoma, lower oil and natural gas prices during 2023, and excess cost positions on the Kansas, Oklahoma and Wyoming conveyances including accumulated interest, which have resulted in no unitholder distributions since July 2023. In addition, on May 18, 2021, the arbitration panel issued its second interim final award over the amount of XTO Energy's settlement in the *Chieftain* class action lawsuit that can be charged to the Trust as a production cost which XTO Energy has estimated to be approximately \$14.6 million net to the Trust. This adjustment would further increase excess costs on the Oklahoma conveyance. The Trustee has prepared a preliminary budget estimating the administrative expenses for the year ending December 31, 2024, and the three months ending March 31, 2025, which assumes no cash inflow from either net profits income or from other sources. The Trustee intends to review options for the Trust which may include alternatives to continuing as a going concern or may include seeking financing to pay the

Hugoton Royalty Trust

NOTES TO FINANCIAL STATEMENTS—(Continued)

Trust obligations during the one-year period after the date the financial statements are issued; however, there can be no assurance that financing will be available on acceptable terms or at all. If financing became available to the Trust, it would have to be repaid, together with interest, and the Trust's expense reserve would have to be replenished prior to any distributions to unitholders.

On July 9, 2020, the Trustee notified XTO Energy of the Trustee's claim to indemnification to the Trust Estate for all liability, expense, claims, damages or loss incurred by the Trustee in connection with the administration of the Trust. The Trustee stated it anticipates seeking reimbursement from XTO Energy upon depletion of the Trust's cash reserve. XTO Energy responded that any indemnity claim to XTO Energy is premature before the Trust Estate is exhausted.

The Trust's financial statements do not include any adjustments that might result from the outcome of these uncertainties.

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).

Hugoton Royalty Trust
NOTES TO FINANCIAL STATEMENTS—(Continued)

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 as calculated by XTO Energy:

	Underlying			
	KS	OK	WY	Total
Cumulative excess costs remaining at 12/31/22	\$ —	\$ —	\$ —	\$ —
Net excess costs (recovery) for the quarter ended 3/31/23	—	—	—	—
Net excess costs (recovery) for the quarter ended 6/30/23	177,356	1,146,689	—	1,324,045
Net excess costs (recovery) for the quarter ended 9/30/23	192,368	5,662,363	803,055	6,657,786
Net excess costs (recovery) for the quarter ended 12/31/23	127,953	(5,414,066)	915,736	(4,370,377)
Cumulative excess costs remaining at 12/31/23	497,677	1,394,986	1,718,791	3,611,454
Accrued interest at 12/31/23	16,861	224,485	27,374	268,720
Total remaining to be recovered at 12/31/23	<u>\$514,538</u>	<u>\$ 1,619,471</u>	<u>\$1,746,165</u>	<u>\$ 3,880,174</u>

	NPI			
	KS	OK	WY	Total
Cumulative excess costs remaining at 12/31/22	\$ —	\$ —	\$ —	\$ —
Net excess costs (recovery) for the quarter ended 3/31/23	—	—	—	—
Net excess costs (recovery) for the quarter ended 6/30/23	141,885	917,351	—	1,059,236
Net excess costs (recovery) for the quarter ended 9/30/23	153,894	4,529,891	642,444	5,326,229
Net excess costs (recovery) for the quarter ended 12/31/23	102,362	(4,331,253)	732,588	(3,496,303)
Cumulative excess costs remaining at 12/31/23	398,141	1,115,989	1,375,032	2,889,162
Accrued interest at 12/31/23	13,489	179,588	21,899	214,976
Total remaining to be recovered at 12/31/23	<u>\$411,630</u>	<u>\$ 1,295,577</u>	<u>\$1,396,931</u>	<u>\$ 3,104,138</u>

For the year ended December 31, 2023, excess costs were \$497,677 (\$398,141 net to the Trust) and recoveries of accrued interest were \$240 (\$192 net to the Trust) on properties underlying the Kansas net profits interests. This includes excess costs of \$127,953 (\$102,362 net to the Trust) for the quarter ended December 31, 2023.

For the year ended December 31, 2023, excess costs were \$1,394,986 (\$1,115,989 net to the Trust) and recoveries of accrued interest were \$943 (\$754 net to the Trust) on properties underlying the Oklahoma net profits interests. This includes recoveries of excess costs of \$5,414,066 (\$4,331,253 net to the Trust) for the quarter ended December 31, 2023.

For the year ended December 31, 2023, excess costs on properties underlying the Wyoming net profits interests increased by \$1,718,791 (\$1,375,032 net to the Trust). This includes excess costs of \$915,736 (\$732,588 net to the Trust) for the quarter ended December 31, 2023.

Underlying cumulative excess costs for the Kansas, Oklahoma and Wyoming conveyances remaining as of December 31, 2023, totaled \$3.9 million (\$3.1 million net to the Trust), including accrued interest of \$0.3 million (\$0.2 million net to the Trust). This balance does not include the portion of the *Chieftain* settlement the Panel determined could be charged as a production cost. XTO Energy has estimated the amount to be approximately \$14.6 million (net to the Trust).

Hugoton Royalty Trust
NOTES TO FINANCIAL STATEMENTS—(Continued)

5. Administration Expense

Administrative expenses are incurred so that the Trustee may meet its reporting obligations to the unitholders and regulatory entities and otherwise manage the administrative functions of the Trust. These obligations include, but are not limited to, all expenses, taxes, compensation to the Trustee for managing the Trust, fees to consultants, accountants, attorneys, transfer agents, other professional and expert persons, expenses for clerical and other administrative assistance, and fees and expenses for all other services. See Item 11. *Executive Compensation*, for further information on the remuneration received by the Trustee.

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. Impairments recorded 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. The Trust did not file a Kansas income tax return for the 2015 through 2021 tax years due to the fact that there were no revenues, income, or deductions attributable to properties located in Kansas in that time period.

Wyoming does not impose a state income tax.

The Trust may be required to bear a portion of the legal settlement costs arising from the *Chieftain* royalty class action settlement. For information on contingencies, including the *Chieftain* class action, see Note 8 to Financial Statements. The Panel has determined the Trust is responsible for a portion of the costs. Pending finalization of all claims included in the arbitration, XTO Energy would have the right to 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 portion of legal settlement costs for which the Trust is determined to be responsible 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.

Unitholders should consult their own tax advisor regarding income tax requirements, if any, applicable to such person's ownership of Trust units.

Hugoton Royalty Trust
NOTES TO FINANCIAL STATEMENTS—(Continued)

7. Related Party Transactions

XTO Energy operates approximately 95 percent 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, 2023, the monthly overhead charge, based on the number of operated wells, was approximately \$1,060,000 (\$848,000 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 and an ExxonMobil affiliate purchases NGLs for a price based upon third-party sales. 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 \$4.1 million for 2023, or 8 percent of total gas sales, \$6.1 million for 2022, or 9 percent of total gas sales.

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

8. Contingencies

Litigation

Royalty Class Action and Arbitration

As previously disclosed, XTO Energy advised the Trustee that it reached a settlement with the plaintiffs in the *Chieftain* class action royalty case. On July 27, 2018, the final plan of allocation was approved by the court. Based on the final plan of allocation, XTO Energy 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 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. The Trust and XTO Energy conducted the interim hearing on the claims related to the *Chieftain* settlement on October 12-13, 2020. In the arbitration, the Trustee contended that the approximately \$24.3 million allocation related to the *Chieftain* settlement was not a production cost and, therefore, there should not be a related adjustment to the Trust's share of net proceeds. However, XTO Energy contended that the approximately \$24.3 million was a production cost and should reduce the Trust's share of net proceeds.

On January 20, 2021, the arbitration panel issued its Corrected Interim Final Award (i) "reject[ing] the Trust's contention that XTO has no right under the Conveyance to charge the Trust with amounts XTO paid under section 1.18(a)(i) as royalty obligations to settle the *Chieftain* litigation" and (ii) stating "[t]he next phase will determine how much of the *Chieftain* settlement can be so charged, if any of it can be, in the exercise of the right found by the Panel." Following briefing by both parties, on May 18, 2021, the Panel issued its second interim final award over the amount of XTO Energy's settlement in the *Chieftain* class action lawsuit that can be charged to the Trust as a production cost. The Panel in its decision has ruled that out of the \$80 million settlement, the "Trust is obligated to pay its share under the Conveyance of the \$48 million that was received by the plaintiffs in the *Chieftain* lawsuit by virtue of the settlement of that litigation. The Trust is not obligated by the Conveyance to pay any share of the \$32 million received by the lawyers for the plaintiffs in the *Chieftain* lawsuit by virtue of the settlement." XTO Energy and the Trustee are in the process of determining the portion of the \$48 million that is allocable to Trust properties to be charged as an excess cost to the Trust, but estimate it to be approximately \$14.6 million net to the Trust.

Hugoton Royalty Trust
NOTES TO FINANCIAL STATEMENTS—(Continued)

The reduction in the Trust's share of net proceeds from the portion of the settlement amount the Panel has ruled may be charged against the Oklahoma conveyance would result in excess costs under the Oklahoma conveyance that would likely result in no distributions under the Oklahoma conveyance while these excess costs are recovered. This award completes the portion of the arbitration related to the *Chieftain* settlement. Excess costs on any individual conveyance would not affect net proceeds to the Trust on any of the other remaining conveyances.

Other Trustee claims related to disputed amounts on the computation of the Trust's net proceeds for 2014 through 2019 and 2021 were bifurcated from the initial arbitration. Although the arbitration is not terminated, the final hearing regarding the remaining dispute over net proceeds, previously scheduled to occur on November 8, 2023, was cancelled. XTO Energy and the Trustee will provide material updates as they become available.

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, based on the information available at this stage of the various proceedings, 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

Hugoton Royalty Trust

NOTES TO FINANCIAL STATEMENTS—(Continued)

reserves, including recovery of cumulative excess costs remaining at year end. Future net cash flows are discounted at an annual rate of 10 percent. 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 XTO Energy's or the Trustee'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 \$2.59 per Mcf in 2023, and \$5.75 per Mcf in 2022. Oil prices used to determine the standardized measure were based on average realized oil prices of \$75.88 per Bbl in 2023, and \$93.46 per Bbl in 2022.

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	
	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)
<i>(in thousands)</i>				
Balance, December 31, 2021	120,475	1,461	23,561	334
Extensions, additions and discoveries	186	83	90	40
Revisions of prior estimates	18,958	378	23,536	307
Production – sales volumes	(9,772)	(246)	(2,441)	(49)
Sales in place	—	—	—	—
Balance, December 31, 2022	129,847	1,676	44,746	632
Extensions, additions and discoveries	471	130	202	56
Revisions of prior estimates	(41,898)	(155)	(36,629)	(506)
Production – sales volumes	(9,398)	(217)	(990)	(11)
Sales in place	—	—	—	—
Balance, December 31, 2023	<u>79,022</u>	<u>1,434</u>	<u>7,329</u>	<u>171</u>

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.

Hugoton Royalty Trust
NOTES TO FINANCIAL STATEMENTS—(Continued)

Proved Developed Reserves

(in thousands)

	Underlying Properties		Net Profits Interests	
	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)
December 31, 2022	129,847	1,676	44,746	632
December 31, 2023	79,022	1,434	7,329	171

Standardized Measure of Discounted Future Net Cash Flows from Proved Reserves

(in thousands)

	December 31	
	2023	2022
<i>Underlying Properties</i>		
Future cash inflows	\$313,585	\$903,302
Future costs:		
Production	279,766	545,894
Development	—	—
Future net cash flows	33,819	357,408
10% discount factor	10,055	162,851
Standardized measure	\$ 23,764	\$194,557
<i>Net Profits Interests</i>		
Future cash inflows	\$ 29,140	\$313,533
Future production taxes	2,084	27,606
Future net cash flows	27,056	285,927
10% discount factor	8,044	130,281
Standardized measure	\$ 19,012	\$155,646

Hugoton Royalty Trust
NOTES TO FINANCIAL STATEMENTS—(Continued)

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

(in thousands)

	2023	2022
<i>Underlying Properties</i>		
Standardized measure, January 1	\$ 194,557	\$ 69,604
Revisions:		
Prices and costs	(174,761)	126,066
Quantity estimates	5,954	16,068
Accretion of discount	17,501	6,758
Future development costs	(9,460)	(2,390)
Production rates and other	18	(80)
Net revisions	(160,748)	146,422
Extensions, additions and discoveries	4,290	2,962
Production	(23,795)	(26,821)
Development costs	9,460	2,390
Sales in place	—	—
Net change	(170,793)	124,953
Standardized measure, December 31	<u>\$ 23,764</u>	<u>\$194,557</u>
<i>Net Profits Interests</i>		
Standardized measure, January 1	\$ 155,646	\$ 55,683
Extensions, additions and discoveries	3,432	2,369
Accretion of discount	14,001	5,406
Revisions of prior estimates, changes in price and other	(142,599)	111,732
Sales in place	—	—
Net profits income	(11,468)	(19,544)
Standardized measure, December 31	<u>\$ 19,012</u>	<u>\$155,646</u>

10. Quarterly Financial Data (Unaudited)

The following is a summary of net profits income, distributable income and distributable income per unit by quarter for 2023 and 2022:

	Net Profits Income	Distributable Income	Distributable Income per Unit
2023			
First Quarter	\$10,459,753	\$10,175,760	\$0.254394
Second Quarter	1,008,161	920,760	0.023019
Third Quarter	—	—	0.000000
Fourth Quarter	—	—	0.000000
	<u>\$11,467,914</u>	<u>\$11,096,520</u>	<u>\$0.277413</u>
2022			
First Quarter	\$ 347,410	\$ —	\$0.000000
Second Quarter	1,856,317	—	0.000000
Third Quarter	9,440,853	8,964,359	0.224109
Fourth Quarter	7,899,818	7,620,680	0.190517
	<u>\$19,544,398</u>	<u>\$16,585,039</u>	<u>\$0.414626</u>

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, 2023.

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, 2023, that have materially affected, or are reasonably likely to materially affect, the Trust's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

The Trust has no directors or officers, and as a result, no such persons adopted or terminated a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement," as each term is defined in Item 408(a) of Regulation S-K.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

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 percent 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, 2023.

(c) *Code of Ethics.* Because the Trust has no employees, it does not have a code of ethics. Employees of the Trustee, Argent Trust Company, must comply with the company's code of ethics which may be found at www.argentfinancial.com.

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 calculated the following annual compensation for the fiscal years ended December 31, 2023 and 2022, as specified in the Trust indenture:

	2023	2022
Argent Trust Company, Trustee (1)	\$82,265	—
Simmons Bank, Trustee (1)	—	\$76,909

- (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.

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 2023.

(b) *Security Ownership of Certain Beneficial Owners.* Based on the Trustee's review of information filed with the SEC as of March 19, 2024, the following table sets forth information with respect to each person known to the Trustee to beneficially own more than 5 percent of the outstanding units.

Name and Address	Amount and Nature of Beneficial Ownership	Percent of Class
Christopher John Heck 2100 E. 377 Granbury, TX 76049	6,220,500 ⁽¹⁾	15.56%

(1) Pursuant to a Schedule 13G/A filed January 19, 2024, Christopher John Heck reported as of December 31, 2023, he beneficially owned 6,220,500 units, of which he had sole voting and dispositive power with respect to 6,215,500 units and shared voting and dispositive power with respect to 5,000 units.

(c) *Security Ownership of Management.* The Trust has no directors or executive officers. Argent Trust Company, the Trustee, held as of February 26, 2024, an aggregate of 203 units in various fiduciary capacities, and it had sole voting and investment power with respect to all such units.

(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

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*.

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. For further information, see Note 7 to Financial Statements under Item 8. *Financial Statements and Supplementary Data*.

As of March 11, 2024, XTO Energy did not own any units.

See Item 11. *Executive Compensation*, for the remuneration received by the Trustee for the fiscal years ended December 31, 2022, through December 31, 2023.

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, 2023 and 2022 are:

	2023	2022
Audit fees-PwC	\$220,000	\$209,000
Audit-related fees	—	—
Tax fees	—	—
All other fees	—	—
	<u>\$220,000</u>	<u>\$209,000</u>

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, 2023 and 2022

Statements of Distributable Income for the years ended December 31, 2023 and 2022

Statements of Changes in Trust Corpus for the years ended December 31, 2023 and 2022

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) Amendment No. 1 to Amended and Restated Royalty Trust Indenture, dated March 24, 1999, of Hugoton Royalty Trust heretofore filed as Exhibit 4.1 to the Trust's Current Report on Form 8-K filed with the Securities and Exchange Commission on April 5, 2023, is incorporated herein by reference.

(c) 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.

(d) 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.

(e) 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

(97) Hugoton Royalty Trust Executive Officer Compensation Recovery Policy

(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 Argent Trust Company, 3838 Oak Lawn Ave, Suite 1720, Dallas, Texas 75219-4518.

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 ARGENT TRUST COMPANY, TRUSTEE

By _____ /s/ NANCY WILLIS
Nancy Willis
Director of Royalty Trust Services

EXXON MOBIL CORPORATION

Date: April 1, 2024

By _____ /s/ WENDI POWELL
Wendi Powell
Upstream Controller

(The Trust has no directors or executive officers.)

March 29, 2024

Tracie White
XTO Energy Inc.
22777 Springwoods Village Parkway
Spring, TX 77389-1425

Re: HGT Consent Letter

Dear Tracie White:

This letter is to confirm that Miller and Lents, Ltd. (M&L) authorizes XTO Energy Inc. (XTO) to use our name and report dated March 28, 2024, related to the Hugoton Royalty Trust (HGT) for use in the electronic filing of the HGT Annual Report on Form 10-K with the SEC.

Please provide us with an exact copy of the Annual Report on form 10-K as electronically filed with the SEC.

Very truly yours,

MILLER AND LENTS, LTD.
Texas Registered Engineering Firm No. F-1442

By /S/ JENNIFER A. GODBOLD

Jennifer A. Godbold, P. E.
Senior Vice President

1. I have reviewed this annual report on Form 10-K of Hugoton Royalty Trust, for which Argent Trust Company acts as Trustee;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, distributable income and changes in trust corpus of the registrant as of, and for, the periods presented in this report;
4. I am responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)), for the registrant and I have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under my supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to me by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under my supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report my conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. I have disclosed, based on my most recent evaluation of internal control over financial reporting, to the registrant's auditors:
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 1, 2024

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

In connection with the Annual Report of Hugoton Royalty Trust (the "Trust") on Form 10-K for the year ended December 31, 2023 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, not in its individual capacity but solely as the Trustee of the Trust, certifies pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to its knowledge:

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

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

Argent Trust Company,
Trustee for Hugoton Royalty Trust

April 1, 2024

By _____ /s/ NANCY WILLIS
Nancy Willis
Director of Royalty Trust Services

Hugoton Royalty Trust
Executive Officer Compensation Recovery Policy
(As adopted November 22, 2023)

This Executive Officer Compensation Recovery Policy (this “**Policy**”) of Hugoton Royalty Trust (the “**Trust**”) is hereby adopted as of November 22, 2023 (the “**Effective Date**”) by Argent Trust Company (the “**Trustee**”) in compliance with Section 10D of the Securities Exchange Act of 1934 and Rule 5608 of the Nasdaq Listing Rules. Certain terms shall have the meanings set forth in “Section 3. Definitions” below.

Section 1. Recovery Requirement

Subject to Section 4 of this Policy, in the event the Trust is required to prepare an Accounting Restatement, then the Trustee hereby directs the Trust, to the fullest extent permitted by governing law, to recover from each Executive Officer the amount received by an Executive Officer, if any, of Erroneously Awarded Compensation, with such recovery occurring reasonably promptly after the Restatement Date relating to such Accounting Restatement. An Executive Officer shall be deemed to have “received” Incentive-Based Compensation in the Trust’s fiscal period during which the Financial Reporting Measure specified in the Incentive-Based Compensation award is attained, even if the payment or grant of the Incentive-Based Compensation occurs after the end of that fiscal period.

The Trustee may effect recovery in any manner consistent with applicable law including, but not limited to, (a) seeking reimbursement of all or part of any Erroneously Awarded Compensation previously received by an Executive Officer and to the extent that the Executive Officer does not reimburse such Erroneously Awarded Compensation, suing and enforcing recovery against the Executive Officer for repayment of the Erroneously Awarded Compensation, together with any expenses (including, without limitation, legal fees) incurred by the Trust in enforcing such recovery, (b) cancelling prior grants of Incentive-Based Compensation, whether vested or unvested, restricted or deferred, or paid or unpaid, and through the forfeiture of previously vested equity awards, (c) cancelling or setting-off against planned future grants of Incentive-Based Compensation, (d) deducting all or any portion of such Erroneously Awarded Compensation from any other remuneration payable by the Trust to such Executive Officer, and (e) any other method authorized by applicable law or contract.

The Trust’s right to recovery pursuant to this Policy is not dependent on if or when the Accounting Restatement is filed with the Securities and Exchange Commission.

Section 2. Incentive-Based Compensation Subject to this Policy.

This Policy applies to all Incentive-Based Compensation received by each Executive Officer on or after the Effective Date:

(i) if such Incentive-Based Compensation was received on or after the date such person became an Executive Officer of the Trust;

(ii) if such Executive Officer served as an Executive Officer at any time during the performance period for that Incentive-Based Compensation; and

(iii) if such Incentive-Based Compensation was received during the three completed fiscal years immediately preceding the Restatement Date (including any transition period that results from a change in the Trust’s fiscal year that is within or immediately following those three completed fiscal years; provided that a transition period of nine to 12 months is deemed to be a completed fiscal year).

This Policy shall apply and govern Incentive-Based Compensation received by any Executive Officer, notwithstanding any contrary or supplemental term or condition in any document, plan or agreement including without limitation any employment contract, indemnification agreement, equity agreement, or equity plan document.

Section 3. Definitions:

For purposes of this Policy, the following terms have the meanings set forth below:

- “**Accounting Restatement**” means an accounting restatement due to the material noncompliance of the Trust with any financial reporting requirement under the securities laws, including any required accounting restatement to correct an error (i) in previously issued financial statements that is material to the previously issued financial statements (commonly referred to as a “Big R” restatement) or (ii) that would result in a material misstatement if the error were corrected in the current period or left uncorrected in the current period (commonly referred to as a “little r” restatement).
- “**Erroneously Awarded Compensation**” means the amount of Incentive-Based Compensation received that exceeds the amount of Incentive-Based Compensation that otherwise would have been received by the Executive Officer had it been determined based on the restated amounts in the Accounting Restatement (computed without regard to any taxes paid). For Incentive-Based Compensation based on the price of units of beneficial interest in the Trust or total unitholder return (“**TUR**”), where the amount of Erroneously Awarded Compensation is not subject to mathematical recalculation directly from the information in the Accounting Restatement the Trust shall: (i) base the calculation of the amount on a reasonable estimate of the effect of the Accounting Restatement on the price of units of beneficial interest in the Trust or TUR upon which the Incentive-Based Compensation received was based; and (ii) retain documentation of the determination of that reasonable estimate and provide such documentation to the Nasdaq Stock Market or, if a class of securities of the Trust is no longer listed on the Nasdaq Stock Market, such other national securities exchange or national securities association on which a class of the Trust’s securities is then listed for trading.
- “**Executive Officer**” has the meaning set forth in Rule 5608(d) of the Nasdaq Listing Rules. For purposes of clarity, “Executive Officer” includes officers or employees of the Trustee who perform policy-making functions for the Trust.
- “**Financial Reporting Measure**” is (i) any measure that is determined and presented in accordance with the accounting principles used in preparing the Trust’s financial statements, or any measure derived wholly or in part from such measure, (ii) unit price and (iii) TUR. A Financial Reporting Measure need not be presented within the Trust’s financial statements or included in a filing with the Securities Exchange Commission.
- “**Incentive-Based Compensation**” means any compensation that is granted, earned, or vested based wholly or in part upon the attainment of a Financial Reporting Measure (including, without limitation, unit price or TUR), including, any short-term or long-term incentive awards, cash bonuses, restricted unit awards that vest based on achievement of a Financial Reporting Measure. Equity awards that vest exclusively upon completion of a specified employment period, without any performance condition, and bonus awards that are discretionary or based on subjective goals or goals unrelated to Financial Reporting Measures, do not constitute Incentive-Based Compensation.
- “**Restatement Date**” means the earlier to occur of (i) the date the Trustee (or an officer or officers of the Trust or Trustee authorized to take such action if action by the board of directors of the Trust or Trustee is not required) concludes, or reasonably should have concluded, that the Trust is required to prepare an Accounting Restatement and (ii) the date a court, regulator, or other legally authorized body directs the Trust to prepare an Accounting Restatement.

Section 4. Exceptions to Recovery

Notwithstanding the foregoing, the Trust is not required to recover Erroneously Awarded Compensation to the extent that the Trustee has made a determination that recovery would be impracticable and that:

- (i) the direct expense paid to a third party to assist in enforcing this Policy would exceed the amount to be recovered (provided, that, before concluding that it would be impracticable to recover based on the expense of enforcement, the Trust must make a reasonable attempt to recover such Erroneously Awarded Compensation and must document such attempts and provide such documentation to the Nasdaq Stock Market);
- (ii) recovery would violate one or more laws of the home country that were adopted prior to November 28, 2022 (provided, that, before concluding that it would be impracticable to recover based on violation of home country law, the Trust must obtain an opinion of home country counsel, acceptable to the Nasdaq Stock Market, that recovery would result in such a violation and provide a copy of such opinion to the Nasdaq Stock Market);
- (iii) recovery would likely cause an otherwise tax-qualified retirement plan, under which benefits are broadly available to employees of the Trust and its subsidiaries, to fail to meet the requirements of 26 U.S.C. 401(a)(13) or 26 U.S.C. 411(a) and regulations thereunder; or
- (iv) any other exception permitted under Rule 5608 of the Nasdaq Listing Rules.

Section 5. No Right to Indemnification or Insurance

The Trust shall not indemnify any Executive Officer against the loss of Erroneously Awarded Compensation or losses arising from any claims relating to the Trust's enforcement of this Policy. In addition, the Trust shall not pay, or reimburse any Executive Officer for, any premiums for a third-party insurance policy purchased by the Executive Officer or any other party that would fund any of the Executive Officer's potential recovery obligations under this Policy.

Section 6. Award Agreements and Plan Documents

The Trustee further directs the Trust to include clawback language in each of the Trust's incentive compensation plans such that each individual who receives Incentive-Based Compensation under those plans understands and agrees that all or any portion of such Incentive-Based Compensation may be subject to recovery by the Trust, and such individual may be required to repay all or any portion of such Incentive-Based Compensation, if (i) recovery of such Incentive-Based Compensation is required by this Policy, (ii) such Incentive-Based Compensation is determined to be based on materially inaccurate financial and/or performance information (which includes, but is not limited to, statements of earnings, revenues or gains); or (iii) repayment of such Incentive-Based Compensation is required by applicable federal or state securities and/or banking laws.

Section 7. Interpretation and Amendment of this Policy

The Trustee, in its discretion, shall have the sole authority to interpret and make any determinations regarding this Policy. Any interpretation, determination, or other action made or taken by the Trustee shall be final, binding, and conclusive on all interested parties. The determination of the Trustee need not be uniform with respect to one or more officers. The Trustee may amend this Policy from time to time in its discretion and shall amend the Policy to comply with applicable law or with any rules or standards adopted by the Nasdaq Stock Market or any national securities exchange on which the Trust's securities are then listed. The Trustee may terminate this Policy at any time.

Any employees of the Trustee who assist in the administration of this Policy shall not be personally liable for any action, determination or interpretation made with respect to this Policy and shall be fully indemnified by the Trust to the fullest extent under applicable law and Trust policy with respect to any such action, determination or

interpretation. The foregoing sentence shall not limit any other rights to indemnification of the employees of the Trustee under applicable law or Trust policy.

Section 8. Other Recoupment Rights.

The Trust intends that this Policy will be applied to the fullest extent of the law. Any right of recoupment under this Policy is in addition to, and not in lieu of, any other remedies or rights of recoupment that may be available to the Trust pursuant to the terms of any similar policy in any employment agreement, equity award agreement, or similar agreement and any other remedies available to the Trust under applicable law. Without by implication limiting the foregoing, following a restatement of the Trust's financial statements, the Trust also shall be entitled to recover any compensation received by the Chief Executive Officer and Chief Financial Officer that is required to be recovered by Section 304 of the Sarbanes-Oxley Act of 2002.

March 28, 2024

Ms. Kameron Fivecoat
Reserves Manager
XTO Energy Inc.
22777 Springwoods Village Parkway
Spring, TX 77389

Re: Underlying Properties (100%)
Relating to the Hugoton Royalty Trust
Reserves and Future Net Revenues
As of December 31, 2023
SEC Price Case

Dear Ms. Fivecoat:

At your request, Miller and Lents, Ltd. (M&L) estimated the proved reserves and future net revenues as of December 31, 2023, attributable to the XTO Energy Inc. (XTO) interest in certain oil and gas properties prior to inclusion in the Hugoton Royalty Trust, i.e., Underlying Properties (100%). The Underlying Properties (100%) include working interest properties from which net profits interests were conveyed to the Hugoton Royalty Trust. The properties consist of approximately 1,340 leases and 1,461 wells located primarily in Kansas, Oklahoma, and Wyoming. The aggregate results of M&L's evaluations are as follows:

Reserves Category	Net Reserves		Future Net Revenues	
	Oil and Condensate MBBL	Gas MMCF	Undiscounted M\$	Discounted at 10% Per Year M\$
Kansas				
Proved Developed Producing	96	4,925	6,750	3,849
Total Proved	96	4,925	6,750	3,849
Oklahoma				
Proved Developed Producing	1,318	56,325	105,652	62,428
Total Proved	1,318	56,325	105,652	62,428
Wyoming				
Proved Developed Producing	21	17,772	18,374	12,385
Total Proved	21	17,772	18,374	12,385
Total Underlying Properties (100%)				
Proved Developed Producing	1,434	79,022	130,776	78,662
Total Proved	1,434	79,022	130,776	78,662

Oil and condensate volumes are expressed in thousand barrels (MBBL). Gas volumes are expressed in million cubic feet (MMCF). Future net revenues are expressed in thousand dollars (M\$).

The report was prepared for the use of XTO in its financial and reserves reporting and was completed on March 28, 2024. M&L performed evaluations, which are designated as the SEC Price Case, using price and expense premises specified by XTO and described in detail on Appendix 1.

Proved reserves and future net revenues were estimated in accordance with the provisions contained in Securities and Exchange Commission Regulation S-X, Rule 4-10(a). The Securities and Exchange Commission definition of proved reserves is shown on Appendix 2 (not included). Gas volumes for each property are stated at

the pressure and temperature bases appropriate for the sales contract or state regulatory authority; therefore, some of the aggregated totals may be stated at a mixed pressure base. No provisions for the possible consequences, if any, of product sales imbalances were included in M&L's projections since M&L received no relevant data. Estimates of future net revenues and discounted future net revenues are not intended and should not be interpreted to represent fair market values for the estimated reserves. In M&L's projections, future costs of abandoning facilities and wells were assumed to be offset by salvage values. Estimated costs, if any, for restoration of producing properties to satisfy environmental standards are beyond the scope of this assignment.

Following Appendix 2 (not included) is a list of exhibits that include annual projections of future production and net revenues for each state and reserves category. Also included in the exhibits are one-line summaries for the total royalty trust and for each state showing the proved reserves and future net revenues for the individual properties. These exhibits should not be relied upon independently of this narrative.

The proved developed producing reserves and production forecasts were estimated by production decline extrapolations, water-oil ratio trends, P/Z declines, or in a few cases, by volumetric calculations. For some properties with insufficient performance history to establish trends, M&L estimated future production by analogy with other properties with similar characteristics. The past performance trends of many properties were influenced by production curtailments, workovers, waterfloods, and/or infill drilling. Actual future production may require that M&L's estimated trends be significantly altered. Reserves estimates from volumetric calculations and from analogies are often less certain than reserves estimates based on well performance obtained over a period during which a substantial portion of the reserves was produced.

The estimated proved developed nonproducing reserves can be produced from existing well bores but require capital costs for recompletions or for pipeline connections. These proved developed nonproducing reserves estimates were based on analogies with other wells that commercially produce from the same formation in the same field. The timing of initial production was provided to M&L by XTO. When actual production history is available for these nonproducing reserves, M&L's reserves estimates may be significantly revised.

The estimated proved undeveloped reserves require significant capital expenditures, such as for planned drilling and completion costs. The proved undeveloped reserves estimates for infill wells are based on analogies to similar infill wells in the same field and/or the production histories of offset wells in the same field. As actual results of the planned drilling become available, M&L's reserves estimates may be significantly revised.

The data employed in M&L's estimations of proved reserves and future net revenues were provided by XTO. The current expenses for each lease were obtained from operating statements provided by XTO except for certain leases where XTO deducted items considered by XTO to be nonrecurring expenditures. No overhead was included for those properties operated by XTO. For some properties, such as large waterfloods, XTO assumed a decline in operating costs due to depleting production that was derived by forecasting a decrease in the property well count. For some gas properties, XTO assumed operating costs would be split between a variable component and a fixed component. The variable component was a constant cost per thousand cubic feet of gas production and the fixed component was a constant cost per well completion. The data provided to M&L by XTO, including, but not limited to, graphical representations and tabulations of past production performance, well tests and pressures, ownership interests, prices, capital expenditures, and operating costs were accepted as represented and were considered appropriate for the purpose of this report. M&L employed all methods, data, procedures, and assumptions considered necessary and appropriate in utilizing the data provided to prepare this report.

The evaluations presented in this report, with the exceptions of those parameters specified by others, reflect M&L's informed judgments and are subject to the inherent uncertainties associated with interpretation of geological, geophysical, and engineering information. These uncertainties include, but are not limited to, (1) the

utilization of analogous or indirect data and (2) the application of professional judgments. Government policies and market conditions different from those employed in this study may cause (1) the total quantity of oil, natural gas liquids, or gas to be recovered, (2) actual production rates, (3) prices received, or (4) operating and capital costs to vary from those presented in this report. At this time, M&L is not aware of any regulations that would affect XTO's ability to recover the estimated reserves.

Miller and Lents, Ltd. is an independent oil and gas consulting firm. No director, officer, or key employee of Miller and Lents, Ltd. has any financial ownership in XTO Energy Inc. or any related company. M&L's compensation for the required investigations and preparation of this report is not contingent on the results obtained and reported, and it has not performed other work that would affect M&L's objectivity. Production of this report was supervised by Jennifer A. Godbold, P.E., an officer of the firm who is a licensed Professional Engineer in the State of Texas and is professionally qualified, with more than 12 years of relevant experience, in the estimation, assessment, and evaluation of oil and gas reserves.

M&L's work papers and data are in its files and available for review upon request. If you have any questions regarding the above, or if M&L can be of further assistance, please call.

Very truly yours,

MILLER AND LENTS, LTD.
Texas Registered Engineering Firm No. F-1442

By /S/ JENNIFER A. GODBOLD

Jennifer A. Godbold, P. E.
Senior Vice President

Hugoton Royalty Trust (100%)**SEC PRICE CASE**

- | | |
|--------------------|---|
| A. Oil Price | Average price during the 12-month period prior to 12/31/23 determined as the arithmetic average of the first-day-of-the-month price for each month during the year 2023. The average price was based on the West Texas Intermediate benchmark price. The arithmetic average of the first-day-of-the-month benchmark prices is \$78.22 per barrel and is held constant through the life of the property. The average realized price, after appropriate adjustments, is \$75.88 per barrel. |
| B. Gas Price | Average price during the 12-month period prior to 12/31/23 determined as the arithmetic average of the first-day-of-the-month price for each month during the year 2023. The average price was based on the Henry Hub benchmark price. The arithmetic average of the first-day-of-the-month benchmark price is \$2.637 per MMBTU and is held constant through the life of the property. The average realized price, after appropriate adjustments is \$2.59 per MCF. |
| C. Operating Costs | Current expenses held constant through the life of the property. For some properties, expenses included a variable component that was a constant cost per unit of gas production and a fixed component that was a constant cost per well completion. |
| D. Discount Rate | 10% per year. |