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

FORM 10-K

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

For the fiscal year ended December 31, 2024

or

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

For the transition period from to

Commission File Number 001-35333

PERMIANVILLE ROYALTY TRUST
(Exact name of registrant as specified in its charter)

Delaware	**45-6259461**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

The Bank of New York Mellon Trust Company, N.A., Trustee
601 Travis Street
16th Floor
Houston, Texas **77002**
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: **(512) 236-6555**

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Units of Beneficial Interest	PVL	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. 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	☐	Accelerated filer	☐
Non-accelerated filer	☒	Smaller reporting company	☒
Emerging growth company	☐		

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

Indicate by check mark whether the registrant 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 the voting and non-voting common equity held by non-affiliates (25,636,039 Units of Beneficial Interest) computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter was $34,320,000.

As of March 19, 2025, 33,000,000 Units of Beneficial Interest of the Trust were outstanding.

Documents Incorporated By Reference: None

TABLE OF CONTENTS

FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (this "Form 10-K") includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical fact included in this Form 10-K, including without limitation the statements under "Trustee's Discussion and Analysis of Financial Condition and Results of Operations" in Part II, Item 7 of this Form 10-K and "Risk Factors" in Part I, Item 1A of this Form 10-K regarding the financial position, business strategy, production and reserve growth, expected capital expenditures, and other plans and objectives for the future operations of COERT Holdings 1 LLC ("COERT" or the "Sponsor") and regarding future matters relating to Permianville Royalty Trust (the "Trust") are forward-looking statements. Such statements may be influenced by factors that could cause actual outcomes and results to differ materially from those projected. Such expectations may not prove to have been correct. When used in this document, the words "believes," "expects," "anticipates," "intends" or similar expressions are intended to identify such forward-looking statements.

The following important factors, in addition to those discussed elsewhere in this Form 10-K, could affect the future results of the energy industry in general, and the Sponsor and the Trust in particular, and could cause actual results to differ materially from those expressed in such forward-looking statements:

- risks associated with the drilling and operation of oil and natural gas wells;
- the amount of future direct operating expenses and development expenses;
- the occurrence or threat of epidemic or pandemic diseases or other public health events or any government response to such occurrence or threat;
- the impact of geopolitical developments and tensions, war and uncertainty involving or in the geographical region of oil producing countries (including the ongoing armed conflicts between Russia and Ukraine and between Israel and Iran and its proxies and any related political or economic responses and counter-responses or otherwise by various global actors or the general effect on the global economy);
- global economic conditions, such as a general slowdown in the global economy, trade barriers and tariffs, supply chain disruptions, inflationary pressures, currency fluctuations, changes in interest rates, and instability of financial institutions;
- the effects of actions by, or disputes among or between members of the Organization of Petroleum Exporting Countries ("OPEC") and other oil-exporting nations with respect to production levels or other matters related to the prices of oil and natural gas;
- the effect of existing and future laws and regulatory actions;
- the effect of changes in commodity prices or alternative fuel prices;
- the prohibition on the Trust's entry into any new hedging arrangements under the terms of the Conveyance;
- conditions in the capital markets;
- competition from others in the energy industry;
- uncertainty of estimates of oil and natural gas reserves and production;
- potential impacts on the Sponsor's business resulting from climate change, greenhouse gas regulations, and the impact of climate change related changes in the frequency and severity of weather patterns; and
- other risks described under the caption "Risk Factors" in Part I, Item 1A of this Form 10-K.

Trust unitholders should not place undue reliance on these forward-looking statements. All forward-looking statements speak only as of the date of this Form 10-K. The Trust does not undertake any obligation to release publicly any revisions to the forward-looking statements to reflect events or circumstances after the date of this Form 10-K or to reflect the occurrence of unanticipated events, unless the securities laws require the Trust to do so.

This Form 10-K describes other important factors that could cause actual results to differ materially from expectations of the Sponsor and the Trust, including under the caption “Risk Factors” in Part I, Item 1A of this Form 10-K. All subsequent written and oral forward-looking statements attributable to the Sponsor or the Trust or persons acting on behalf of the Sponsor or the Trust are expressly qualified in their entirety by such factors. The Trust assumes no obligation, and disclaims any duty, to update these forward-looking statements.

GLOSSARY OF CERTAIN OIL AND NATURAL GAS TERMS

In this Form 10-K the following terms have the meanings specified below.

Bbl—One barrel of 42 U.S. gallons liquid volume, used herein in reference to crude oil and other liquid hydrocarbons.

Boe—One barrel of oil equivalent, computed on an approximate energy equivalent basis that one Bbl of crude oil equals approximately six Mcf of natural gas.

Btu—A British Thermal Unit, a common unit of energy measurement.

Completion—The installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Development Well—A well drilled into a proved oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Differential—The difference between a benchmark price of oil and natural gas, such as the NYMEX crude oil spot, and the wellhead price received.

Estimated future net revenues—Also referred to as “estimated future net cash flows.” The result of applying current prices of oil and natural gas to estimated future production from oil and natural gas proved reserves, reduced by estimated future expenditures, based on current costs to be incurred, in developing and producing the proved reserves, excluding overhead.

Farm-in or farm-out agreement—An agreement under which the owner of a working interest in an oil or natural gas lease typically assigns the working interest or a portion of the working interest to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a “farm-in” while the interest transferred by the assignor is a “farm-out.”

Field—An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

GAAP—Accounting principles generally accepted in the United States of America.

Gross acres or gross wells—The total acres or wells, as the case may be, in which a working interest is owned.

MBbl—One thousand barrels of crude oil or condensate.

MBoe—One thousand barrels of oil equivalent.

Mcf—One thousand cubic feet of natural gas.

MMBoe—One million barrels of oil equivalent.

MMBtu—One million British Thermal Units.

MMcf—One million cubic feet of natural gas.

Net acres or net wells—The sum of the fractional working interests owned in gross acres or wells, as the case may be.

Net profits interest—A nonoperating interest that creates a share in gross production from an operating or working interest in oil and natural gas properties. The share is measured by net profits from the sale of production after deducting costs associated with that production.

Net revenue interest—An interest in all oil and natural gas produced and saved from, or attributable to, a particular property, net of all royalties, overriding royalties, Net Profits Interests, carried interests, reversionary interests and any other burdens to which the interest is subject.

Plugging and abandonment—Activities to remove production equipment and seal off a well at the end of a well's economic life.

Proved developed reserves—Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved reserves—Under SEC rules, proved reserves are defined as:

Those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons, LKH, as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil, HKO, elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved undeveloped reserves—Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

PV-10— A non-GAAP financial measure of the present value of estimated future net revenues to be generated from the production of proved reserves, net of estimated future production and development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to income taxes, discounted at 10% per annum.

Recompletion—The completion for production of an existing wellbore in another formation from which that well has been previously completed.

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

Working interest—The right granted to the lessee of a property to explore for and to produce and own oil, natural gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

Workover—Operations on a producing well to restore or increase production.

PART I

Item 1. *Business.*

Permianville Royalty Trust (the “Trust”), previously known as Enduro Royalty Trust, is a Delaware statutory trust formed in May 2011 pursuant to a trust agreement (as amended and restated, and as further amended, the “Trust Agreement”) among Enduro Resource Partners LLC (“Enduro”), as trustor, The Bank of New York Mellon Trust Company, N.A. (the “Trustee”), as trustee, and Wilmington Trust Company (the “Delaware Trustee”), as Delaware Trustee.

The Trust was created to acquire and hold for the benefit of the Trust unitholders a net profits interest representing the right to receive 80% of the net profits from the sale of oil and natural gas production from certain properties in the states of Texas, Louisiana and New Mexico held by Enduro as of the date of the conveyance of the net profits interest to the Trust (the “Net Profits Interest”). The properties in which the Trust holds the Net Profits Interest are referred to as the “Underlying Properties.”

In connection with the closing of the initial public offering of units of beneficial interest in the Trust (“Trust Units”) in November 2011, Enduro Operating LLC, a Texas limited liability company and a wholly owned subsidiary of Enduro (“Enduro Operating”), and Enduro Texas LLC, a Texas limited liability company and a wholly owned subsidiary of Enduro (“Enduro Texas”), merged, with each entity surviving the merger. By virtue of the merger, Enduro Texas retained all rights, title and interest to the Net Profits Interest. Enduro Operating and Enduro Texas entered into a Conveyance of Net Profits Interest, dated effective as of July 1, 2011 (as supplemented and amended to date, the “Conveyance”), to effect the transfer of the Net Profits Interest from Enduro Operating to Enduro Texas.

On November 8, 2011, Enduro Texas merged with and into the Trust (the “Trust Merger”) pursuant to an Agreement and Plan of Merger dated November 3, 2011 (the “Trust Merger Agreement”). Under the terms of the Trust Merger Agreement, the Trust continued as the surviving entity, and the limited liability company interest in Enduro Texas held by Enduro prior to the effective time of the Trust Merger converted into the right to receive 33,000,000 Trust Units. Further, by virtue of the Trust Merger, the Trust retained all right, title and interest to the Net Profits Interest (including the right to enforce the Conveyance against Enduro Operating, as grantor). On November 8, 2011, the Trust, Enduro Operating and Enduro Texas entered into a Supplement to Conveyance of Net Profits Interest to acknowledge that The Bank of New York Mellon Trust Company, N.A., as Trustee, is deemed the grantee under the Conveyance and a party thereto.

Immediately following the Trust Merger, Enduro completed an initial public offering of 13,200,000 Trust Units at a price to the public of $22 per unit.

In October 2013, Enduro completed a secondary offering of 11,200,000 Trust Units at a price to the public of $13.85 per unit. The Trust did not sell any Trust Units in the offering and did not receive any proceeds from the offering. After the completion of the secondary offering, Enduro owned 8,600,000 Trust Units, or 26% of the issued and outstanding Trust Units.

At a special meeting of Trust unitholders held on August 30, 2017, unitholders approved several proposals, including amendments to the Trust Agreement and Conveyance. In September 2017, Enduro, the Trustee and the Delaware Trustee entered into the First Amendment to Amended and Restated Trust Agreement, which amended certain provisions of the Trust Agreement to, among other things, allow Enduro to sell interests in the Underlying Properties free and clear of the Net Profits Interest with the approval of Trust unitholders holding at least 50% of the then outstanding units of the Trust at a meeting held in accordance with the requirements of the Trust Agreement. This amendment reduced the required threshold for approval of such sales from holders of 75% to holders of 50% of the outstanding Trust Units. To effect the same changes as those included in the amended Trust Agreement, Enduro, the Trustee and the Delaware Trustee also entered into the First Amendment to Conveyance of Net Profits Interest. As a result of the Trust unitholders approving amendments to the Trust Agreement and Conveyance and the approval of the divestiture of certain properties in the Permian Basin, Enduro and the Trustee entered into the Partial Release, Reconveyance and Termination Agreement (the “Partial Release”). Pursuant to the terms of the Partial Release, the Trustee, on behalf of the Trust, reconveyed, terminated and released to Enduro the Net Profits Interest with respect to certain of the Underlying Properties sold pursuant to eight letter agreements or purchase and sale agreements, as applicable, entered into between Enduro and eight separate counterparties.

On August 31, 2018, COERT Holdings 1 LLC (“COERT” or the “Sponsor”) acquired the Underlying Properties and all of the outstanding Trust Units owned by Enduro (the “Sale Transaction”). In connection with the Sale Transaction, COERT assumed all of Enduro’s obligations under the Trust Agreement and other instruments to which Enduro and the Trustee were parties. COERT is a Delaware limited liability company engaged in the production and development of oil and natural gas from properties located in the Rockies, the Permian Basin of west Texas and southeastern New Mexico, and the Arklatex region of Texas and Louisiana.

On May 3, 2023, the Sponsor notified the Trustee that the Sponsor had entered into an agreement to divest certain acreage and associated production in the Permian Basin (the “2023 Divestiture Properties”) that constituted part of the Underlying Properties and were therefore burdened by the Trust’s Net Profits Interest, for a total purchase price of approximately $6.7 million. On July 19, 2023, at a special meeting of Trust unitholders, the unitholders approved the foregoing transaction and the release of the Trust’s Net Profits Interest in the 2023 Divestiture Properties. On August 9, 2023, the Sponsor completed the sale of the 2023 Divestiture Properties, and the Trustee, on behalf of the Trust, reconveyed, terminated and released to the Sponsor the Net Profits Interest with respect to the 2023 Divestiture Properties. For additional information regarding this transaction, see “Trustee’s Discussion and Analysis of Financial Condition and Results of Operations—Sale of 2023 Divestiture Properties” in Part II, Item 7 of this Form 10-K.

The Net Profits Interest is passive in nature and neither the Trust nor the Trustee has any management control over or responsibility for costs relating to the operation of the Underlying Properties. The Net Profits Interest entitles the Trust to receive 80% of the net profits from the sale of oil and natural gas production from the Underlying Properties during the term of the Trust. The Trust Agreement provides that the Trust’s business activities are limited to owning the Net Profits Interest and any activity reasonably related to such ownership, including activities required or permitted by the terms of the Conveyance. As a result, the Trust is not permitted to acquire other oil and natural gas properties or net profits interests or otherwise to engage in activities beyond those necessary for the conservation and protection of the Net Profits Interest.

The Trust has no employees. Administrative functions are performed by the Trustee pursuant to the Trust Agreement. The Trustee has no authority over or responsibility for, and no involvement with, any aspect of the oil and gas operations or other activities on the Underlying Properties. The duties of the Trustee are specified in the Trust Agreement and by the laws of the state of Delaware, except as modified by the Trust Agreement. The Trustee’s principal duties consist of:

- collecting cash attributable to the Net Profits Interest;
- paying expenses, charges and obligations of the Trust from the Trust’s assets;
- distributing distributable cash to the Trust unitholders;
- causing to be prepared and distributed a tax information report for each Trust unitholder and preparing and filing tax returns on behalf of the Trust;
- causing to be prepared and filed reports required to be filed under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), and by the rules of any securities exchange or quotation system on which the Trust Units are listed or admitted to trading;
- causing to be prepared and filed a reserve report by or for the Trust by independent reserve engineers as of December 31 of each year in accordance with criteria established by the Securities and Exchange Commission (the “SEC”);
- establishing, evaluating and maintaining a system of internal control over financial reporting in compliance with the requirements of the Sarbanes-Oxley Act of 2002;
- enforcing the Trust’s rights under certain agreements; and
- taking any action it deems necessary or advisable to best achieve the purposes of the Trust.

In connection with the formation of the Trust, the Trust entered into several agreements with Enduro that imposed obligations upon Enduro, including the Conveyance and a Registration Rights Agreement, which COERT assumed in connection with the Sale Transaction. The Trustee has the power and authority under the Trust Agreement to enforce these agreements on behalf of the Trust. Additionally, the Trustee may from time to time supplement or amend the Conveyance and the Registration Rights Agreement without the approval of Trust unitholders in order to cure any ambiguity, to correct or supplement any defective or inconsistent provisions, to grant any benefit to all of the Trust unitholders, to comply with changes in applicable law or to change the name of the Trust. Such supplement or amendment, however, may not materially adversely affect the interests of the Trust unitholders.

The Trustee may create a cash reserve to pay for future liabilities of the Trust. In addition, the Trustee may authorize the Trust to borrow money to pay administrative or incidental expenses of the Trust that exceed its cash on hand and available reserves. The Trustee may authorize the Trust to borrow from any person, including the Trustee, the Delaware Trustee or an affiliate thereof, although none of the Trustee, the Delaware Trustee nor any affiliate thereof intends to lend funds to the Trust. The Trustee also may cause the Trust to mortgage its assets to secure payment of the indebtedness. The terms of such indebtedness and security interest, if the Trustee, Delaware Trustee or an affiliate thereof were to loan funds, would be similar to the terms that such entity would grant to a similarly situated commercial customer with whom it did not have a fiduciary relationship. Under the terms of the Trust Agreement, COERT has provided the Trust with a $1.2 million letter of credit to be used by the Trust if the Trust's cash on hand (including available cash reserves) is not sufficient to pay ordinary course administrative expenses. If the Trust requires more than the $1.2 million under the letter of credit to pay administrative expenses, COERT has agreed to loan funds to the Trust necessary to pay such expenses. If the Trust borrows funds or draws on the letter of credit, no further distributions will be made to Trust unitholders until such amounts borrowed or drawn are repaid.

In November 2021, the Trustee notified COERT of the Trustee's intent to build a cash reserve for the payment of future known, anticipated or contingent expenses or liabilities of the Trust. From February 2022 through March 2023, the Trustee withheld $37,833, and commencing with the distribution to Trust unitholders paid in April 2023 has been withholding, and in the future intends to withhold, $50,000, from the funds otherwise available for distribution each month to gradually build a cash reserve of approximately $2.3 million. The Trustee may increase or decrease the targeted cash reserve amount at any time, and may increase or decrease the rate at which it is withholding funds to build the cash reserve at any time, without advance notice to the Trust unitholders. Cash held in reserve will be invested as required by the Trust Agreement. Any cash reserved in excess of the amount necessary to pay or provide for the payment of future known, anticipated or contingent expenses or liabilities eventually will be distributed to Trust unitholders, together with interest earned on the funds. As of December 31, 2024, this cash reserve totaled $1,241,386.

Each month, after paying Trust obligations and expenses, the Trustee distributes to the Trust unitholders any remaining proceeds received from the Net Profits Interest. The cash held by the Trustee as a reserve against future liabilities or for distribution at the next distribution date may be held in a noninterest-bearing account or may be invested in:

- interest-bearing obligations of the United States government;
- money market funds that invest only in United States government securities;
- repurchase agreements secured by interest-bearing obligations of the United States government; or
- bank certificates of deposit.

The Trust is not subject to any pre-set termination provisions based on a maximum volume of oil or natural gas to be produced or the passage of time. The Trust will dissolve upon the earliest to occur of the following:

- the Trust, upon approval of the holders of at least 75% of the outstanding Trust Units, sells the Net Profits Interest;
- the annual cash proceeds received by the Trust attributable to the Net Profits Interest are less than $2 million for each of any two consecutive years;
- the holders of at least 75% of the outstanding Trust Units vote in favor of dissolution; or
- the Trust is judicially dissolved.

Upon dissolution of the Trust, the Trustee would sell all of the Trust's assets, either by private sale or public auction, and, after payment or the making of reasonable provision for payment of all liabilities of the Trust, distribute the net proceeds of the sale to the Trust unitholders.

Marketing and Post-Production Services

Pursuant to the terms of the Conveyance, the Sponsor has the responsibility to market, or cause to be marketed, the oil and natural gas production attributable to the Net Profits Interest in the Underlying Properties. The terms of the Conveyance restrict the Sponsor from charging any fee for marketing production attributable to the Net Profits Interest other than fees for marketing paid to non-affiliates. Accordingly, a marketing fee is not deducted (other than fees paid to non-affiliates) in the calculation of the Net Profits Interest's share of net profits. The net profits to the Trust from the sales of oil and natural gas production from the Underlying Properties attributable to the Net Profits Interest is determined based on the same price that the Sponsor receives for sales of oil and natural gas production attributable to the Sponsor's interest in the Underlying Properties. However, if the oil or natural gas is processed, the net profits receive the same processing upgrade or downgrade that the Sponsor receives.

The operators of the Underlying Properties sell the oil produced from the Underlying Properties to third-party crude oil purchasers. Oil production from the Underlying Properties is typically transported by truck from the field to the closest gathering facility or refinery. The operators sell the majority of the oil production from the Underlying Properties under contracts using market sensitive pricing. The price received by the operators for the oil production from the Underlying Properties is usually based on a regional price applied to equal daily quantities in the month of delivery that is then reduced for differentials based upon delivery location and oil quality. Natural gas produced by the operators is marketed and sold to third-party purchasers. The natural gas is sold pursuant to contracts with such third parties, and the sales contracts are in their secondary terms and are on a month-to-month basis. The contract prices are based on a published regional index price, after adjustments for Btu content, transportation and related charges.

The following purchasers individually accounted for ten percent or more of sales from the Underlying Properties that were included in calculating the Trust's "Income from net profits interest" for the periods presented. The table provides the percentage represented by each of these purchasers during the periods presented:

	Year Ended December 31,	
	2024	2023
Pioneer Natural Resources USA	23%	18%
Phillips 66	18%	23%
Holly Frontier	10%	9%

Competition and Markets

The oil and natural gas industry is highly competitive. The Sponsor competes with major oil and natural gas companies and independent oil and natural gas companies for oil and natural gas, equipment, personnel and markets for the sale of oil and natural gas. Many of these competitors are financially stronger than the Sponsor, but even financially troubled competitors can affect the market because of their need to sell oil and natural gas at any price to attempt to maintain cash flow. Because the Sponsor and the third-party operators of the Underlying Properties are subject to competitive conditions in the oil and natural gas industry, the Trust's Net Profits Interest is indirectly subject to those same competitive conditions.

Oil and natural gas compete with other forms of energy available to customers, primarily based on price. These alternate forms of energy include electricity, coal and fuel oils. Changes in the availability or price of oil, natural gas or other forms of energy, as well as business conditions, conservation, legislation, regulations and the ability to convert to alternate fuels and other forms of energy may affect the demand for oil and natural gas.

Future prices for oil and natural gas will directly impact Trust distributions, estimates of reserves attributable to the Trust's interests and estimated and actual future net revenues to the Trust. In view of the many uncertainties that affect the supply and demand for oil and natural gas, neither the Trust nor the Sponsor can make reliable predictions of future oil and natural gas supply and demand or future product prices. Nevertheless, lower product prices generally will result in lower distributions, lower estimates of reserves attributable to the Trust's interests and lower estimated and actual future net revenues to the Trust.

All the Trust's assets are located in the United States. The operators of the Underlying Properties sell the oil and natural gas produced from the Underlying Properties to third-party purchasers in the United States. Demand for natural gas generally is higher in the winter months, but otherwise seasonal factors do not affect the Trust.

Description of Trust Units

Each Trust Unit is a unit of beneficial interest in the Trust and is entitled to receive cash distributions from the Trust on a pro rata basis. Each Trust unitholder has the same rights regarding his or her Trust Units as every other Trust unitholder has regarding his or her units. The Trust Units are in book-entry form only and are not represented by certificates. The Trust had 33,000,000 Trust Units outstanding as of March 19, 2025.

Distributions and Income Computations

Each month, the Trustee determines the amount of funds available for distribution to the Trust unitholders. Available funds are the excess cash, if any, received by the Trust from the Net Profits Interest and other sources (such as interest earned on any amounts reserved by the Trustee) that month, over the Trust's liabilities for that month. Available funds are reduced by any cash the Trustee decides to hold as a reserve against future liabilities. The holders of Trust Units as of the applicable record date (generally the last business day of each calendar month) are entitled to monthly distributions payable on or before the 10th business day after the record date. If the net profits for any computation period is a negative amount, the Trust will receive no payment for that period, and any such negative amount plus accrued interest will be deducted from gross profits in the following computation period for purposes of determining the net profits for that following computation period.

Unless otherwise advised by counsel or the Internal Revenue Service ("IRS"), the Trustee will treat the income and expenses of the Trust for each month as belonging to the Trust unitholders of record on the monthly record date. Trust unitholders generally will recognize income and expenses for tax purposes in the month the Trust receives or pays those amounts, rather than in the month the Trust distributes the cash to which such income or expenses (as applicable) relate. Minor variances may occur. For example, the Trustee could establish a reserve in one month that would not result in a tax deduction until a later month.

Transfer of Trust Units

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

Periodic Reports

The Trustee files all required Trust federal and state income tax and information returns. The Trustee prepares and mails to Trust unitholders annual reports that Trust unitholders need to correctly report their share of the income and deductions of the Trust. The Trustee also causes to be prepared and filed reports that are required to be filed under the Exchange Act and by the rules of any securities exchange or quotation system on which the Trust Units are listed or admitted to trading, and also causes the Trust to comply with the provisions of the Sarbanes-Oxley Act of 2002, including but not limited to, establishing, evaluating and maintaining a system of internal control over financial reporting in compliance with the requirements of Section 404 thereof.

Each Trust unitholder and his or her representatives may examine, for any proper purpose, during reasonable business hours, the records of the Trust and the Trustee, subject to such restrictions as are set forth in the Trust Agreement.

Liability of Trust Unitholders

Under the Delaware Statutory Trust Act, Trust unitholders are entitled to the same limitation of personal liability extended to stockholders of private corporations for profit under the General Corporation Law of the State of Delaware. The courts in jurisdictions outside of Delaware, however, might not give effect to such limitation.

Voting Rights of Trust Unitholders

The Trustee or Trust unitholders owning at least 10% of the outstanding Trust Units may call meetings of Trust unitholders. The Trust is responsible for all costs associated with calling a meeting of Trust unitholders, unless such meeting is called by Trust unitholders, in which case the Trust unitholders who called the meeting are responsible for all such costs. Meetings must be held in such location as the Trustee designates in the notice of such meeting. The Trustee must send notice of the time and place of the meeting and the matters to be acted upon to all of the Trust unitholders at least 20 days and not more than 60 days before the meeting. Trust unitholders representing a majority of Trust Units outstanding must be present or represented by proxy to have a quorum. Each Trust unitholder is entitled to one vote for each Trust Unit owned. Abstentions and broker non-votes will not be deemed to be a vote cast.

Unless the Trust Agreement otherwise requires, a matter may be approved or disapproved by the affirmative vote of a majority of the Trust Units present in person or by proxy at a meeting where there is a quorum. This is true even if holders of a majority of the total Trust Units did not approve it. The affirmative vote of the holders of at least 75% of the outstanding Trust Units is required to:

- dissolve the Trust;
- amend the Trust Agreement (except with respect to certain matters that do not adversely affect the rights of Trust unitholders in any material respect); or
- approve the sale of all the assets of the Trust (including the sale of the Net Profits Interest).

In September 2017, following a special meeting of Trust unitholders at which unitholders approved amendments to the Trust Agreement, Enduro, the Trustee and the Delaware Trustee entered into the First Amendment to Amended and Restated Trust Agreement, which amended certain provisions of the Trust Agreement to, among other things, allow Enduro (and, therefore, following the Sale Transaction, the Sponsor) to sell interests in the Underlying Properties free and clear of the Net Profits Interest with the approval of Trust unitholders holding at least 50% of the then outstanding units of the Trust at a meeting held in accordance with the requirements of the Trust Agreement. This amendment reduced the required threshold for approval of such sales from holders of 75% to holders of 50% of the outstanding Trust Units.

In addition, the Trustee may make certain amendments to the Trust Agreement without approval of the Trust unitholders.

Computation of Net Profits

The provisions of the Conveyance governing the computation of the net profits are detailed and extensive. The following information summarizes the material provisions of the Conveyance related to the computation of the net profits, but is qualified in its entirety by the text of the Conveyance, which is incorporated by reference as an exhibit to this Form 10-K.

Net Profits Interest

The amounts paid to the Trust with respect to the Net Profits Interest are based on, among other things, the definitions of “gross profits” and “net profits” contained in the Conveyance and described below. Under the Conveyance, net profits are computed monthly, and 80% of the aggregate net profits attributable to the sale of oil and natural gas production from the Underlying Properties for each calendar month will be paid to the Trust on or before the end of the following month. The Sponsor will not pay to the Trust any interest on the net profits held by the Sponsor prior to payment to the Trust, provided that such payments are timely made.

“*Gross profits*” means the aggregate amount received by the Sponsor from and after July 1, 2011 from sales of oil and natural gas produced from the Underlying Properties that are not attributable to a production month that occurs prior to June 1, 2011 (after deducting the appropriate share of all royalties and any overriding royalties, production payments and other similar charges (in each case, in existence as of June 1, 2011) and other than certain excluded proceeds, as described in the Conveyance), including all proceeds and consideration received (i) directly or indirectly, for advance payments, (ii) directly or indirectly, under take-or-pay and similar provisions of production sales contracts (when credited against the price for delivery of production) and (iii) under balancing arrangements. Gross profits do not include consideration for the transfer or sale of any Underlying Property by the Sponsor or any subsequent owner to any new owner, unless the Net Profits Interest is released (as is permitted under certain circumstances). Gross profits also do not include any amount for oil or natural gas lost in production or marketing or used by the owner of the Underlying Properties in drilling, production and plant operations.

“*Net profits*” means, as more fully set forth in the Conveyance, gross profits less the following costs, expenses and, where applicable, losses, liabilities and damages all as actually incurred by the Sponsor and attributable to the Underlying Properties on or after July 1, 2011 but that are not attributable to a production month that occurs prior to July 1, 2011 (as such items are reduced by any offset amounts, as described in the Conveyance):

- with the exception of certain costs and expenses related to 20 wells located in the Haynesville Shale identified in the Conveyance, all costs for (i) drilling, development, production and abandonment operations, (ii) all direct labor and other services necessary for drilling, operating, producing and maintaining the Underlying Properties and workovers of any wells located on the Underlying Properties, (iii) treatment, dehydration, compression, separation and transportation, (iv) all materials purchased for use on, or in connection with, any of the Underlying Properties and (v) any other operations with respect to the exploration, development or operation of hydrocarbons from the Underlying Properties;

- all losses, costs, expenses, liabilities and damages with respect to the operation or maintenance of the Underlying Properties for (i) defending, prosecuting, handling, investigating or settling litigation, administrative proceedings, claims, damages, judgments, fines, penalties and other liabilities, (ii) the payment of certain judgments, penalties and other liabilities, (iii) the payment or restitution of any proceeds of hydrocarbons from the Underlying Properties, (iv) complying with applicable local, state and federal statutes, ordinance, rules and regulations, (v) tax or royalty audits and (vi) any other loss, cost, expense, liability or damage with respect to the Underlying Properties not paid or reimbursed under insurance;

- all taxes, charges and assessments (excluding federal and state income, transfer, mortgage, inheritance, estate, franchise and like taxes) with respect to the ownership of, or production of hydrocarbons from, the Underlying Properties;

- all insurance premiums attributable to the ownership or operation of the Underlying Properties for insurance actually carried with respect to the Underlying Properties, or any equipment located on any of the Underlying Properties, or incident to the operation or maintenance of the Underlying Properties;

- all amounts and other consideration for (i) rent and the use of or damage to the surface, (ii) delay rentals, shut-in well payments, minimum royalties and similar payments and (iii) fees for renewal, extension, modification, amendment, replacement or supplementation of the leases included in the Underlying Properties;

- all amounts charged by the relevant operator as overhead, administrative or indirect charges specified in the applicable operating agreements or other arrangements covering the Underlying Properties or operations with respect thereto;

- to the extent that the Sponsor is the operator of certain of the Underlying Properties and there is no operating agreement covering such portion of the Underlying Properties, those overhead, administrative or indirect charges that are allocated by the Sponsor to such portion of the Underlying Properties;

- if, as a result of the occurrence of the bankruptcy or insolvency or similar occurrence of any purchaser of hydrocarbons produced from the Underlying Properties, any amounts previously credited to the determination of the net profits are reclaimed from the Sponsor, then the amounts reclaimed;

- all costs and expenses for recording the Conveyance and, at the applicable times, terminations and/or releases thereof;

- amounts previously included in gross profits but subsequently paid as a refund, interest or penalty; and

- at the option of the Sponsor (or any subsequent owner of the Underlying Properties), amounts reserved for approved development expenditure projects, including well drilling, recompletion and workover costs, which amounts will at no time exceed $2.0 million in the aggregate, and will be subject to the limitations described below (provided that such costs shall not be debited from gross profits when actually incurred).

As mentioned above, the costs deducted in the net profits determination will be reduced by certain offset amounts. The offset amounts are further described in the Conveyance, and include, among other things, certain net proceeds attributable to the treatment or processing of hydrocarbons produced from the Underlying Properties and certain non-production revenues, including salvage value for equipment related to plugged and abandoned wells. If the offset amounts exceed the costs during a monthly period, the ability to use such excess amounts to offset costs will be deferred and utilized as offsets in the next monthly period to the extent such amounts, plus accrued interest thereon, together with other offsets to costs, for the applicable month, are less than the costs arising in such month.

The Trust is not liable to the owners of the Underlying Properties or the operators for any operating capital or other costs or liabilities attributable to the Underlying Properties. The Trustee expects to make distributions to Trust unitholders monthly; however, if the net profits for any computation period is a negative amount, the Trust will receive no payment for that period, and any such negative amount plus accrued interest will be deducted from gross profits in the following computation period for purposes of determining the net profits for that following computation period.

The Trust uses the modified cash basis of accounting to report Trust receipts of net profits and payments of expenses incurred. This comprehensive basis of accounting other than GAAP corresponds to the accounting permitted for royalty trusts by the SEC as specified by Staff Accounting Bulletin Topic 12:E, *Financial Statements of Royalty Trusts.* The Net Profits Interest represents the right to receive revenues (oil and natural gas sales), less direct operating expenses (lease operating expenses and production and property taxes) and development expenses of the Underlying Properties, multiplied by 80%. Cash distributions of the Trust will be made based on the amount of cash received by the Trust with respect to the corresponding production month pursuant to terms of the Conveyance.

Additional Provisions

If a controversy arises as to the sales price of any production, then for purposes of determining gross profits:

- any proceeds that are withheld for any reason (other than at the request of the Sponsor) are not considered received until such time that the proceeds are actually collected;

- amounts received and promptly deposited with a non-affiliated escrow agent will not be considered to have been received until disbursed to the Sponsor by the escrow agent; and

- amounts received and not deposited with an escrow agent will be considered to have been received.

The Trustee is not obligated to return any cash received from the Net Profits Interest. Any overpayments made to the Trust by the Sponsor due to adjustments to prior calculations of net profits or otherwise will reduce future amounts payable to the Trust until the Sponsor recovers the overpayments plus interest at a prime rate (as described in the Conveyance).

The Conveyance generally permits the Sponsor to transfer without the consent or approval of the Trust unitholders all or any part of its interest in the Underlying Properties, subject to the Net Profits Interest. The Trust unitholders are not entitled to any proceeds of a sale or transfer of the Sponsor's interest. Except in certain cases where the Net Profits Interest is released, following a sale or transfer, the Underlying Properties will continue to be subject to the Net Profits Interest, and the gross profits attributable to the transferred property will be calculated, paid and distributed by the transferee to the Trust. The Sponsor will have no further obligations, requirements or responsibilities with respect to any such transferred interests.

In addition, the Sponsor may, without the consent of the Trust unitholders, require the Trustee to release the Net Profits Interest associated with any lease that accounts for no more than 0.25% of the total production from the Underlying Properties in the prior 12 months, provided that the Net Profits Interest covered by such releases cannot exceed, during any 12-month period, an aggregate fair market value to the Trust of $500,000. These releases will be made only in connection with a sale by the Sponsor to a non-affiliate of the relevant Underlying Properties and are conditioned upon an amount equal to the fair value to the Trust of such Net Profits Interest being treated as an offset amount against costs and expenses. In May 2023, the Sponsor sold approximately $0.3 million in non-producing, non-cash flowing acreage to a private oil company, free and clear of the Net Profits Interest, as permitted under the Trust Agreement. The proceeds from this sale attributable to the Trust's Net Profits Interest were included in the distribution that was paid to Trust unitholders on August 14, 2023.

As the designated operator of a property included in the Underlying Properties, the Sponsor may enter into farm-out, operating, participation and other similar agreements to develop the property, but any transfers made in connection with such agreements will be made subject to the Net Profits Interest. The Sponsor may enter into any of these agreements without the consent or approval of the Trustee or any Trust unitholder.

The Sponsor has the right to release, surrender or abandon its interest in any Underlying Property that will no longer produce (or be capable of producing) hydrocarbons in paying quantities (determined without regard to the Net Profits Interest). Upon such release, surrender or abandonment, the portion of the Net Profits Interest relating to the affected property will also be released, surrendered or abandoned, as applicable. The Sponsor also has the right to abandon an interest in the Underlying Properties if (a) such abandonment is necessary for health, safety or environmental reasons or (b) the hydrocarbons that would have been produced from the abandoned portion of the Underlying Properties would reasonably be expected to be produced from wells located on the remaining portion of the Underlying Properties.

The Sponsor must maintain books and records sufficient to determine the amounts payable to the Trust with respect to the Net Profits Interest. Monthly and annually, the Sponsor must deliver to the Trustee a statement of the computation of the net profits for each computation period. The Trustee has the right to inspect and review the books and records maintained by the Sponsor during normal business hours and upon reasonable notice. The Sponsor has further agreed to provide the Trust and Trustee with all information and services as are reasonably necessary to fulfill the purposes of the Trust, including such accounting, bookkeeping and informational services as may be necessary for the preparation of reports the Trust is required to prepare or file in accordance with applicable tax and securities laws, exchange listing rules and other requirements, including reserve reports and tax returns. Following the sale of all or any portion of the Underlying Properties, the purchaser will be bound by the obligations of the Sponsor under the Trust Agreement and the Conveyance with respect to the portion sold.

U.S. Federal Income Tax Matters

The following is a summary of certain U.S. federal income tax matters that may be relevant to the Trust unitholders. This summary is based upon current provisions of the Internal Revenue Code of 1986, as amended (the “Code”), existing and proposed Treasury regulations thereunder and current administrative rulings and court decisions, all of which are subject to changes that may or may not be retroactively applied. No attempt has been made in the following summary to comment on all U.S. federal income tax matters affecting the Trust or the Trust unitholders.

The summary has limited application to non-U.S. persons and persons subject to special tax treatment such as, without limitation: banks, insurance companies or other financial institutions; Trust unitholders subject to the alternative minimum tax; tax-exempt organizations; dealers in securities or commodities; regulated investment companies; real estate investment trusts; traders in securities that elect to use a mark-to-market method of accounting for their securities holdings; non-U.S. Trust unitholders that are “controlled foreign corporations” or “passive foreign investment companies”; persons that are S-corporations, partnerships or other pass-through entities; persons that own their interest in the Trust Units through S-corporations, partnerships or other pass-through entities; persons that at any time own more than 5% of the aggregate fair market value of the Trust Units; expatriates and certain former citizens or long-term residents of the United States; U.S. Trust unitholders whose functional currency is not the U.S. dollar; persons who hold the Trust Units as a position in a hedging transaction, “straddle”, “conversion transaction” or other risk reduction transaction; or persons deemed to sell the Trust Units under the constructive sale provisions of the Code. Each Trust unitholder should consult his or her own tax advisor with respect to his or her particular circumstances.

Classification and Taxation of the Trust

Tax counsel to the Trust advised the Trust at the time of formation that, for U.S. federal income tax purposes, in its opinion, the Trust would be treated as a grantor trust and not as an unincorporated business entity. No ruling has been or will be requested from the IRS or another taxing authority. The remainder of the discussion below is based on tax counsel’s opinion, at the time of formation, that the Trust will be classified as a grantor trust for U.S. federal income tax purposes. As a grantor trust, the Trust is not subject to U.S. federal income tax at the trust level. Rather, each Trust unitholder is considered for U.S. federal income tax purposes to own its proportionate share of the Trust’s assets directly as though no Trust were in existence. The income of the Trust is deemed to be received or accrued by the Trust unitholder at the time such income is received or accrued by the Trust, rather than when distributed by the Trust. Each Trust unitholder is subject to tax on its proportionate share of the income and gain attributable to the assets of the Trust and is entitled to claim its proportionate share of the deductions and expenses attributable to the assets of the Trust, subject to applicable limitations, in accordance with the Trust unitholder’s tax method of accounting and taxable year without regard to the taxable year or accounting method employed by the Trust.

The Trust files annual information returns, reporting to the Trust unitholders all items of income, gain, loss, deduction and credit. The Trust allocates these items of income, gain, loss, deduction and credit to Trust unitholders based on record ownership on the monthly record dates. It is possible that the IRS or another taxing authority could disagree with this allocation method and 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 this issue and result in an increase in the administrative expense of the Trust in subsequent periods.

Under current law, the highest marginal U.S. federal income tax rate applicable to ordinary income of individuals is 37%, and the highest marginal U.S. federal income tax rate applicable to long-term capital gains (generally, gains from the sale or exchange of certain investment assets held for more than one year) and qualified dividends of individuals is generally 20%. Such marginal tax rates may be effectively increased due to the phaseout of personal exemptions and certain limitations and prohibitions on itemized deductions. The highest marginal U.S. federal income tax rate applicable to corporations is 21%, and such rate applies to both ordinary income and capital gains.

Section 1411 of the Code imposes a 3.8% Medicare tax on certain investment income earned by individuals, estates, and trusts (and a reduced 1.4% tax on certain tax-exempt organizations). For these purposes, investment income generally will include a unitholder's allocable share of the trust's interest and royalty income plus the gain recognized from a sale of Trust Units. In the case of an individual, the tax is imposed on the lesser of (i) the individual's net investment income from all investments, or (ii) the amount by which the individual's modified adjusted gross income exceeds specified threshold levels depending on such individual's U.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.

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 Code, the taxpayer generally must recapture the amount deducted for depletion as ordinary income (to the extent of gain realized on the disposition of the property). This depletion recapture rule applies to any disposition of property that was placed in service by the taxpayer after December 31, 1986. Detailed rules set forth in Sections 1.1254-1 through 1.1254-6 of the U.S. Treasury Regulations govern dispositions of property after March 13, 1995. The IRS likely will take the position that a unitholder must recapture depletion upon the disposition of a unit.

Classification of the Net Profits Interest

Tax counsel to the Trust advised the Trust at the time of formation that, for U.S. federal income tax purposes, based upon the reserve report and representations made by the Trust regarding the expected economic life of the Underlying Properties and the expected duration of the Net Profits Interest, in its opinion the Net Profits Interest attributable to proved developed reserves will and the Net Profits Interest attributable to proved undeveloped reserves should be treated as continuing, nonoperating economic interests in the nature of royalties payable out of production from the mineral interests they burden. No assurance can be given that the IRS or another taxing authority will not assert that the Net Profits Interest should be treated differently. Any such different treatment could affect the amount, timing and character of income, gain or loss in respect of an investment in Trust Units.

Reporting Requirements for Widely-Held Fixed Investment Trusts

The Trustee assumes that some Trust Units are held by middlemen, as such term is broadly defined in the Treasury regulations (and includes custodians, nominees, certain joint owners and brokers holding an interest for a custodian 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. The Bank of New York Mellon Trust Company, N.A., 601 Travis Street, Houston, Texas 77002, telephone number 1-512-236-6545, is the representative of the Trust that will provide the tax information in accordance with applicable Treasury regulations governing the information reporting requirements of the Trust as a WHFIT. 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 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. Any generic tax information provided by the Trustee of the Trust is intended to be used only to assist Trust unitholders in the preparation of their federal and state income tax returns.

Available Trust Tax Information

In compliance with the Treasury regulations reporting requirements for WHFITs and the dissemination of Trust tax reporting information, the Trustee provides a generic tax information reporting booklet which is intended to be used only to assist Trust unitholders in the preparation of their federal and state income tax returns. This tax information booklet can be obtained at www.permianvilleroyaltytrust.com.

Environmental Matters and Regulation

General. For purposes of the discussion in this section, the oil and natural gas production operations conducted on the properties that are subject to the Net Profits Interest are referred to as the "Sponsor's operations." The Sponsor's oil and natural gas exploration and production operations are subject to stringent and comprehensive federal, regional, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may impose significant obligations on the Sponsor's operations, including requirements to:

- obtain permits to conduct regulated activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas;
- restrict the types, quantities and concentration of materials that can be released into the environment in the performance of drilling, completion and production activities;
- initiate investigatory and remedial measures to mitigate pollution from former or current operations, such as restoration of drilling pits and plugging of abandoned wells; and
- apply specific health and safety criteria addressing worker protection.

Failure to comply with environmental laws and regulations may result in the assessment of significant administrative, civil and criminal sanctions, including monetary penalties, the imposition of joint and several liability, investigatory and remedial obligations, and the issuance of injunctions limiting or prohibiting some or all of the Sponsor's operations. Moreover, these laws, rules and regulations may restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. The Sponsor has advised the Trustee that it believes that it is in substantial compliance with all existing environmental laws and regulations applicable to its current operations and that its continued compliance with existing requirements will not have a material adverse effect on the cash distributions to the Trust unitholders. Although the Trump Administration had taken steps aimed at reducing federal regulatory burdens and costs for oil and natural gas production operations, the recent trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly construction, drilling, water management, completion, emission or discharge limits or waste handling, disposal or remediation obligations could have a material adverse effect on the Sponsor's development expenses, results of operations and financial position. The Sponsor may be unable to pass on those increases to its customers. Moreover, accidental releases or spills may occur in the course of the Sponsor's operations, and there can be no assurance that the Sponsor will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons.

The following is a summary of certain existing environmental, health and safety laws and regulations to which the Sponsor's business operations are subject.

Hazardous substance and wastes. The Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), also known as the Superfund law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be jointly and severally responsible for the release of a "hazardous substance" into the environment. These persons include current and prior owners or operators of the site where the release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these "responsible persons" may be liable for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA also authorizes the U.S. Environmental Protection Agency ("EPA") and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. Although petroleum, natural gas, and natural gas liquids are excluded from the definition of "hazardous substance" under CERCLA, the Sponsor handles materials in the course of its operations that may be regulated as CERCLA hazardous substances, despite the so-called "petroleum exclusion."

The Sponsor also generates solid and hazardous wastes that are subject to the requirements of the Resource Conservation and Recovery Act, as amended ("RCRA"), and comparable state statutes. RCRA imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. In the course of its operations, The Sponsor generates petroleum hydrocarbon wastes and ordinary industrial wastes that may be classified as hazardous wastes under RCRA and comparable state laws. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, production, and development of crude oil or natural gas are currently regulated under RCRA as non-hazardous wastes. While many exploration and production wastes are exempt from regulation as hazardous waste, these wastes are generally subject to non-hazardous waste regulation under RCRA and applicable state regulations. Many state governments have specific regulations and guidance for exploration and production wastes, including the wastes associated with hydraulic fracturing activities.

The properties upon which the Sponsor conducts its operations have been used for oil and natural gas exploration and production for many years. Although the Sponsor and, as applicable, the Sponsor's predecessor, Enduro, may have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons and wastes may have been disposed of or released at or from the real properties upon which the Sponsor conducts its operations, or at or from other, offsite locations, where these petroleum hydrocarbons and wastes have been taken for treatment or disposal. In addition, the properties upon which the Sponsor conducts its operations may have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or hydrocarbons was not under the Sponsor's control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, the Sponsor could be required to investigate, remove or remediate previously disposed wastes, to clean up contaminated property and to perform response actions to prevent future contamination.

Water discharges. The federal Clean Water Act ("CWA") and analogous state laws impose restrictions and strict controls on the discharge of pollutants into "waters of the United States" and waters within the scope of the state law, respectively. Pursuant to the CWA and applicable state laws, permits must be obtained to discharge pollutants into regulated waters. Any such discharge of pollutants into regulated waters must be performed in accordance with the terms of the permit issued by the EPA or the applicable state agency or both. The discharge of wastewater from most onshore oil and gas exploration and production activities is currently prohibited east of the 98th meridian. Additionally, in June 2016, the EPA issued a final rule implementing wastewater pretreatment standards that prohibit onshore unconventional oil and natural gas extraction facilities from sending certain wastewater directly to publicly owned treatment works ("POTW"). Unconventional extraction facilities are allowed by 40 CFR Part 437 to send wastewater to an off-site private centralized wastewater treatment ("CWT") facility in most circumstances. CWT facilities can either discharge treated water directly to surface waters or send it to a POTW. In 2018, the EPA concluded a study of the treatment and discharge of oil and gas wastewater that could lead to changes in requirements for discharge of produced water under Part 437, including more stringent requirements or a prohibition on discharge of produced water from CWT facilities. Any restriction of disposal options for hydraulic fracturing waste and other changes to CWA discharge requirements may result in increased costs.

The discharge of dredge and fill material in waters of the United States, including wetlands, is also prohibited unless authorized by a permit issued under CWA Section 404 by the U.S. Army Corps of Engineers ("USACE"). CWA Section 401 provides that the applicant for a Section 404 USACE permit for the discharge of dredge and fill materials must seek a Section 401 water quality certification by applying to the state in which the discharge will occur for the state to determine if the discharge will comply with the state's approved water quality program. In some instances, this process could result in delay in issuance of the permit, more stringent permit requirements, or denial of the permit.

How the EPA and the USACE define "waters of the United States" ("WOTUS"), which defines the extent of geographic jurisdiction under the CWA, can impact the Sponsor's regulatory and permitting obligations under the CWA. In 2023, the EPA and the USACE issued a final rule (the "2023 rule") that is described by the EPA and the USACE as following the 1986 regulations as modified by subsequent U.S. Supreme Court decisions and guidance issued by the EPA and USACE interpreting the decisions. Shortly thereafter, the Supreme Court issued its decision in Sackett II which overturned a substantial portion of the basis for the 2023 rule. The USACE and the EPA subsequently amended the 2023 rule and excluded a number of types of wetlands and streams from CWA jurisdiction, but the rule is subject to litigation regarding the sufficiency of the agencies' interpretation of the Sackett II decision. The 2023 rule is presently in effect in about half of the states while it is enjoined in the other half. In those states where the rule is enjoined, the EPA and the USACE define WOTUS in accordance with an earlier regulatory definition adjusted in light of the Supreme Court's Sackett II decision. The Sponsor's regulatory obligations and permitting costs will continue to be subject to remaining uncertainty around the definition of WOTUS and the scope of CWA regulation, given the ongoing litigation.

USACE Nationwide Permits ("NWPs") are a streamlined form of permitting used to authorize development activities with minimal individual or cumulative adverse effects in wetlands or other waters of the United States under the CWA. Some NWPs are also used to authorize activities that impact traditional navigable waters under the Rivers and Harbors Act. NWP 12 will expire in March 2026 and be replaced with a new version. In addition, a federal court in Washington, D.C. is currently hearing a challenge to NWP 12. An adverse decision in the litigation may restrict or remove the ability to use NWP 12 to permit regulated impacts, resulting in the need to apply for a more time-consuming individual permit. This could result in additional cost and time for permitting projects.

In February 2025, the USACE began implementing emergency permitting procedures as directed by President Trump's Executive Order Declaring a National Energy Emergency. This may result in substantially decreased timeframes for receiving Section 404 permits in the case of energy projects subject to the Executive Order.

Finally, the Oil Pollution Act of 1990, as amended ("OPA"), which amends the CWA, establishes standards for prevention, containment and cleanup of oil spills into waters of the United States. The OPA requires measures to be taken to prevent the accidental discharge of oil into waters of the United States from onshore production facilities. Measures under the OPA and/or the CWA include inspection and maintenance programs to minimize spills from oil storage and conveyance systems; the use of secondary containment systems to prevent spills from reaching nearby waterbodies; proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill; and the development and implementation of spill prevention, control and countermeasure ("SPCC") plans to prevent and respond to oil spills. The OPA also subjects owners and operators of facilities in certain instances to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a spill. The Sponsor has developed and implemented SPCC plans for the Underlying Properties as required under the CWA.

Hydraulic fracturing. Various federal and state initiatives are underway to regulate, or further investigate, the environmental impacts of hydraulic fracturing, a practice that involves the pressurized injection of water, chemicals and other substances into rock formation to stimulate production of oil and natural gas. The U.S. Congress has considered legislation to amend the federal Safe Drinking Water Act ("SDWA") to subject hydraulic fracturing operations to regulation under the SDWA's Underground Injection Control Program and to require the disclosure of chemicals used in the hydraulic fracturing process. Any such legislation could make it easier for third parties opposed to hydraulic fracturing to initiate legal proceedings against companies. In December 2016, the EPA issued a final report on the potential impacts of hydraulic fracturing on drinking water resources. The report did not find widespread, systematic impacts to drinking water from hydraulic fracturing; at the same time, the report acknowledged information gaps that limited EPA's ability to fully assess the potential impacts to drinking water resources. To date, the EPA has taken no further action in response to the December 2016 report. However, in April 2024, the BLM issued a final rule to reduce the waste of natural gas from venting, flaring, and leaks during oil and gas production activities on federal and American Indian leases.

On August 16, 2012 the EPA published final rules that extend New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAPs") to certain exploration and production operations. The final rule requires the use of reduced emission completions or "green completions" on all hydraulically fractured gas wells constructed or refractured after January 1, 2015. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. In response to some of these challenges, the EPA amended the rule to extend compliance dates for certain storage vessels and may issue additional revised rules in response to additional such requests in the future. Only a portion of these new rules appear to affect the Sponsor's operations at this time by requiring new air emissions controls, equipment modification, maintenance, monitoring, recordkeeping and reporting. Although these new requirements will increase the Sponsor's operating and capital expenditures and it is possible that the EPA will adopt further regulation that could further increase the Sponsor's operating and capital expenditures, the Sponsor does not currently expect such existing and new regulations will have a material adverse impact on its operations or financial results.

Some states have adopted, and other states are considering adopting, regulations that could restrict or impose additional requirements relating to hydraulic fracturing in certain circumstances, including the disclosure of information regarding the substances used in the hydraulic fracturing process. Such federal or state legislation could require the disclosure of chemical constituents used in the fracturing process to state or federal regulatory authorities who could then make such information publicly available. Disclosure of chemicals used in the fracturing process could make it easier for third parties opposing hydraulic fracturing to initiate legal proceedings against producers and service providers based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is regulated at the federal level, the Sponsor's and the third-party operators' fracturing activities could become subject to additional permit requirements or operational restrictions, to associated permitting delays and potential increases in costs. In December 2014, the Governor of New York announced that the state would maintain its moratorium on hydraulic fracturing in the state. Further, some local governments have imposed moratoria on drilling permits within city limits so that local ordinances may be reviewed to assess their adequacy to address such activities. Similar measures could be considered or implemented in the jurisdictions in which the Underlying Properties are located. However, in May 2015, the Texas legislature enacted a bill preempting local bans on hydraulic fracturing. Meanwhile, in Texas, specific oil and natural gas regulations apply to oil and gas operations, including the drilling, completion and operations of wells, and the disposal of waste oil and salt water. In October 2023, the Texas Railroad Commission ("RRC") announced draft amendments to its water protection rules to, among other things, encourage waste recycling. There are also procedures incident to the plugging and abandonment of dry holes or other non-operational wells, all as governed by the applicable governing state agency. As an example, the RRC adopted rules in 2014 requiring companies seeking permits for disposal wells to provide seismic activity data in permit applications. The rules also allow the RRC to modify, suspend, or terminate permits if a disposal well is determined to be causing seismic activity. Determinations by the RRC under these rules may adversely affect our operations.

Air emissions. The federal Clean Air Act, as amended ("CAA"), and comparable state laws and regulations restrict the emission of air pollutants from many sources and also impose various monitoring and reporting requirements. These laws and regulations may require the Sponsor to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, and to comply with stringent air emissions permit or regulatory requirements or utilize specific equipment or technologies to control emissions. Obtaining permits has the potential to delay the development of the Sponsor's properties.

The EPA has established pollution control standards for oil and gas sources under the CAA. In 2012 and 2016, the EPA adopted federal New Source Performance Standards ("NSPS") that require the reduction of volatile organic compound and sulfur dioxide emissions from certain fractured and refractured natural gas wells for which well completion operations are conducted and further require that most wells use reduced emission completions, also known as "green completions." These regulations also establish specific requirements regarding emissions from production-related wet seal and reciprocating compressors, pumps, and from pneumatic controllers and storage vessels, and for equipment leaks. These NSPS apply to sources that are newly constructed or modified after the rules' applicability dates. More recently, the EPA adopted a final rule in 2024 that will directly regulate volatile organic compound and methane emissions from oil and gas sources constructed or modified after December 2022 and will require reductions in both pollutants through its regulation of flaring, compressors, pumps, storage vessels, process controllers, well completions and liquids unloading, and equipment leaks. Additionally, the EPA for the first time adopted emissions guidelines that will apply to existing oil and gas sources and that require reductions in volatile organic compound and methane emissions that are largely equivalent to the requirements for new sources. The existing source emissions guidelines are to be implemented through state plans, with expected compliance dates for existing sources arriving in 2029.

The EPA is also charged with establishing National Ambient Air Quality Standards ("NAAQS"), the implementation of which can indirectly impact the Sponsor's operations. The CAA directs the EPA to review each NAAQS every five years to ensure that the standards are protective of public health and welfare. This process routinely results in the tightening of those standards, and in October 2015, the EPA lowered the ozone NAAQS from 75 to 70 parts per billion. In December 2020, the EPA published a final rule that retained without revision the 2015 NAAQS ozone standard. More recently, however, in February 2024, the EPA announced a final rule that will lower the annual standard for fine particulate matter from 12 micrograms per cubic meter to 9 micrograms per cubic meter. State or federal implementation of the NAAQS could result in stricter permitting or regulatory requirements, delay or prohibit the Sponsor's ability to obtain such permits, and result in increased expenditures for pollution control equipment.

The 2024 presidential election in the United States may impact the air quality-related requirements that apply to the Sponsor. The Trump Administration may adopt a different approach to many actions taken under the prior presidential administration, including the 2024 revisions to the emissions standards and guidelines for new and existing sources in the oil and gas industry, as well as the 2024 changes to the NAAQS for fine particulate matter. The outcome of the Trump Administration's evaluation of the prior administration's regulatory approach is not certain at this time, but President Trump has made it clear that his energy agenda prioritizes an increase in domestic oil and gas production.

The Sponsor may be required to incur certain capital expenditures for air pollution control equipment or other air emissions-related issues, The Sponsor currently does not expect that such requirements will have a material adverse effect on its operations.

Climate change. In response to its 2009 finding that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") may present an endangerment to public health and the environment, the EPA has issued regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. These regulations include limits on tailpipe emissions from motor vehicles, preconstruction and operating permit requirements for certain large stationary sources, and methane emissions standards for certain new, modified and reconstructed oil and gas sources—as well as the EPA's methane emissions guidelines for existing oil and gas sources that were adopted in 2024. The EPA also has adopted rules requiring the reporting of GHG emissions from specified large greenhouse gas emission sources in the United States, as well as certain onshore oil and natural gas production facilities, on an annual basis. On January 20, 2025, President Trump announced the withdrawal of the United States from the Paris Climate Agreement. President Trump also issued an executive order directing the EPA to review the legality and continuing applicability of its 2009 GHG endangerment finding. The outcome of that review is not currently known; however, it has the potential to eliminate the basis for the EPA's regulation of GHGs under the CAA.

The EPA has established GHG standards for oil and gas sources based on the GHG endangerment finding. In 2024, the EPA adopted a final rule that will directly regulate volatile organic compound and methane emissions from new oil and gas sources and will require reductions in GHG and volatile organic compound emissions through its regulation of flaring, compressors, pumps, storage vessels, process controllers, well completions and liquids unloading, and equipment leaks. At the same time, the EPA adopted emissions guidelines that will apply to existing oil and gas sources and that require reductions in volatile organic compound and methane emissions that are largely equivalent to the requirements for new sources. The existing source emissions guidelines are to be implemented through state plans, with expected compliance dates for existing sources arriving in 2029.

The Inflation Reduction Act of 2022 (the "IRA") included new Clean Air Act section 136(c) directing the EPA to collect the Waste Emissions Charge ("WEC") from facilities in the oil and gas sector that report more than 25,000 tons of carbon dioxide equivalent emissions in a calendar year. The charge will first apply to methane emissions from calendar year 2024. The charge is determined by comparing actual reported methane emissions to statutorily established "methane intensity figures" that are based on gas production or throughput, with a charge assessed for every ton of methane emissions that exceeds the facility's allowable emissions based on the applicable methane intensity figure. The charge will be $900 per ton for 2024 emissions, and will increase to $1,200 and then $1,500 per ton in subsequent years. The program includes key exemptions, most notably a regulatory compliance exemption that applies to and exempts the emissions from facilities that are subject to and in complete compliance with EPA's new or existing source methane requirements. The EPA adopted new rules to implement the WEC program in November 2024; however, the fate of the WEC and the EPA rules implementing the WEC is unclear. In February 2025, the United States House of Representatives and Senate both passed resolutions to repeal the EPA's 2024 WEC rules under the Congressional Review Act ("CRA"), and on March 14, 2025 President Trump signed the resolution repealing those rules under the CRA. In addition, the United States House of Representatives and Senate may be considering amendment or repeal of certain portions of the IRA, including the statutory provisions establishing the WEC.

In addition to the federal actions, more than one-third of the states have begun taking actions to control and/or reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Although most of the state-level initiatives to date have focused on large sources of GHG emissions, such as coal-fired electric plants, it is possible that smaller sources of emissions could become subject to GHG emission limitations or allowance purchase requirements in the future. For example, the states of Colorado and New Mexico have adopted rules regulating GHGs from the oil and gas industry that are based on the federal standards. Congress may in the future consider adopting other legislation to reduce emissions of greenhouse gases. Any one of these climate change regulatory and legislative initiatives could have a material adverse effect on the Sponsor's business, capital expenditures, financial condition and results of operations.

The adoption and implementation of regulations imposing reporting obligations on, or limiting emissions of GHGs from, the Sponsor's equipment and operations could require the Sponsor to incur costs to reduce emissions of GHGs associated with its operations or could adversely affect demand for the natural gas it produces. Legislation or regulations that may be adopted to address climate change could also affect the markets for the Sponsor's products by making its products more or less desirable than competing sources of energy. To the extent that its products are competing with higher GHG-emitting energy sources, the Sponsor's products may become more desirable in the market with more stringent limitations on GHG emissions. To the extent that its products are competing with lower GHG-emitting energy, the Sponsor's products may become less desirable in the market with more stringent limitations on greenhouse gas emissions. The Sponsor cannot predict with any certainty at this time how these possibilities may affect its operations.

Finally, some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such significant physical effects were to occur, they could have an adverse effect on the Sponsor's assets and operations and cause the Sponsor to incur costs in preparing for and responding to them. Additionally, energy needs could increase or decrease as a result of extreme weather conditions, depending on the duration and magnitude of those conditions.

National Environmental Policy Act. The National Environmental Policy Act ("NEPA") requires the federal government to undertake an environmental review prior to making a decision on most proposed federal actions – such as permits, leases, and rights-of-way. Until 2025, agencies undertook NEPA reviews pursuant to binding regulations issued by the White House Council on Environmental Quality ("CEQ") as well as pursuant to the federal agency's own NEPA procedures. CEQ issued its rules after being directed to do so by an Executive Order issued in the Carter Administration. After two federal courts held that CEQ did not have authority to issue binding regulations, the Trump Administration revoked the Carter Administration Executive Order and directed CEQ to withdraw the regulations. In their place, agencies are directed to develop procedures that hew to the statutory text over the course of 2025 with the goal of having them finalized in early 2026. In the meantime, agencies will continue to use their own NEPA procedures and may continue to follow the CEQ regulations, using them as guidance. This may result in delays and uncertainty in permitting reviews as agencies adjust to a new NEPA approach.

Endangered Species Act. The federal Endangered Species Act, as amended ("ESA"), prohibits take of listed endangered, and in some cases threatened, species. Under the ESA, federal agencies are obligated to consult with the U.S. Fish and Wildlife Service or National Marine Fisheries Service if an agency's actions, including permit actions, may affect listed species or designated critical habitat. If endangered species are located in areas of the Underlying Properties where seismic surveys, development activities or abandonment operations may be conducted, the work could be prohibited or delayed or expensive mitigation may be required, depending on the implications for protected species and designated critical habitat. On August 27, 2019, the U.S. Fish and Wildlife Service published a final rule adopting several changes to the federal regulations that implement the ESA, including changes to the procedures and criteria for listing or removing species from the Lists of Endangered and Threatened Wildlife and Plants and for designating critical habitat. The Biden Administration rescinded one of the rules adopted by the prior administration, dealing with critical habitat, and issued a revised rule making changes to the federal consultation process. These changes could make a federal review process occasioned by the application for permits, rights of way, or leases more complex in certain circumstances. In addition, designation of new species as threatened or endangered could cause the Sponsor to incur additional costs arising from species protection measures, could result in limitations on activities, and could require a more complex regulatory compliance process. In January 2025, the Trump Administration directed the use of the emergency consultation procedures for permitting for energy projects in the Declaring a National Energy Emergency Executive Order.

Employee health and safety. The operations of the Sponsor are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, as amended ("OSHA"), and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens.

Where You Can Find Other Information

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

Item 1A. *Risk Factors.*

The risk factors summarized and detailed below could materially harm production from the Underlying Properties, operating results and/or the Trust's financial condition, adversely affect proceeds to the Trust and cash distributions to Trust unitholders, and/or cause the price of the Trust Units to decline. These are not all the risks the Trust faces, and other factors not presently known to the Trust or that the Trust currently believes are immaterial may also affect the Trust if they occur.

SUMMARY OF RISK FACTORS

The following is a summary of some of the risks and uncertainties that could materially affect the Trust's business, financial condition and results of operations. You should read this summary together with the more detailed description of each risk factor contained below.

Business and Operating Risks

- Prices of oil and natural gas fluctuate, and lower prices could reduce proceeds to the Trust and cash distributions to Trust unitholders.

- Actual reserves and future production may be less than current estimates, which could reduce cash distributions by the Trust and the value of the Trust Units.

- The ability or willingness of OPEC and other oil exporting nations to set and maintain production levels has a significant impact on oil and natural gas commodity prices.

- Third-party operators operate all of the wells on the Underlying Properties; therefore, the Sponsor is not in a position to control the timing of development efforts, the associated costs or the rate of production of the reserves on such properties.

- Developing oil and natural gas wells and producing oil and natural gas are costly and high-risk activities with many uncertainties that could adversely affect future production from the Underlying Properties.

- Shortages of equipment, services and qualified personnel could increase costs of developing and operating the Underlying Properties and reduce the amount of cash available for distribution to Trust unitholders.

- The amount of cash available for distribution by the Trust depends in part on access to and operation of gathering, transportation and processing facilities.

- Adverse developments in Texas, Louisiana or New Mexico could adversely impact the results of operations and cash flows of the Underlying Properties and reduce the amount of cash available for distribution to Trust unitholders.

Financial Risks

- The Trust Units may lose value as a result of title deficiencies with respect to the Underlying Properties.

- The oil and natural gas reserves attributable to the Underlying Properties are depleting assets and production from those reserves will diminish over time.

- An increase in the differential between the price realized by the Sponsor for oil and natural gas produced from the Underlying Properties and the NYMEX or other benchmark price of oil or natural gas could reduce the net profits payable to the Trust and, therefore, the cash distributions by the Trust and the value of the Trust Units.

- Higher production and development costs and expenses related to the Underlying Properties and other costs and expenses incurred by the Trust, without concurrent increases in revenue, will reduce the amount of cash available for distribution to Trust unitholders.

- The Trust has established a cash reserve for contingent liabilities and to pay expenses in accordance with the Trust Agreement, which would reduce net profits payable to the Trust and distributions to Trust unitholders.

- The amount of cash available for distribution by the Trust could be reduced by expenses caused by uninsured claims.

- The Sponsor’s ability to perform its obligations to the Trust could be limited by restrictions under its debt agreements.

- The bankruptcy of the Sponsor or any of the third-party operators could impede the operation of the wells and the development of the proved undeveloped reserves.

- In the event of the bankruptcy of the Sponsor, if a court were to hold that the Net Profits Interest was part of the bankruptcy estate, the Trust may be treated as an unsecured creditor with respect to the Net Profits Interest attributable to properties in Louisiana and New Mexico.

Risks Related to the Structure of the Trust

- The Trust is passive in nature and neither the Trustee nor the Trust unitholders have any ability to influence the Sponsor or control the operations or development of the Underlying Properties.

- Subject to specified limitations, the Sponsor may transfer all or a portion of the Underlying Properties at any time without Trust unitholder consent.

- Under certain circumstances, the Trustee must sell the Net Profits Interest and dissolve the Trust prior to the expected termination of the Trust.

- Conflicts of interest could arise between the Sponsor and its affiliates, on the one hand, and the Trust and the Trust unitholders, on the other hand.

- The Trust is administered by a Trustee who cannot be replaced except by a majority vote of the Trust unitholders at a special meeting.

- Trust unitholders have limited ability to enforce provisions of the Conveyance.

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

- The Trust is a smaller reporting company and benefits from certain reduced governance and disclosure requirements, which could make the Trust Units less attractive to investors.

Risks Related to Ownership of the Trust Units

- If the Trust cannot meet continued listing requirements, the NYSE may delist the Trust Units.

- The Sponsor may sell Trust Units in the public or private markets, and such sales may have an adverse impact on the trading price of the Trust Units.

- The trading price for the Trust Units may not reflect the value of the Net Profits Interest held by the Trust.

- Courts outside of Delaware may not recognize the limited liability of Trust unitholders.

Legal, Environmental and Regulatory Risks

- The operations on the Underlying Properties are subject to complex federal, state, local and other laws and regulations, including environmental regulations, that could adversely affect the cost, manner or feasibility of conducting operations on them or expose the operator to significant liabilities.

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

- Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Cybersecurity Risks

- Cyber-attacks or other failures in telecommunications or information technology systems could result in information theft, data corruption and significant disruption of the Sponsor’s or the Trustee’s operations.

Tax Risks Related to the Trust Units

- If the IRS were to determine (and be sustained in that determination) that the Trust is not a “grantor trust” for U.S. federal income tax purposes, the Trust could be subject to more complex and costly tax reporting requirements that could reduce the amount of cash available for distribution to Trust unitholders.

- Trust unitholders are required to pay taxes on their share of the Trust’s income even if they do not receive any cash distributions from the Trust.

- A portion of any tax gain on the disposition of the Trust Units could be taxed as ordinary income.

- The IRS may challenge the Trust’s approach to allocating its items of income, gain, loss and deduction between transferors and transferees of the Trust 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 Trust Unit is transferred.

BUSINESS AND OPERATING RISKS

Prices of oil and natural gas fluctuate, and lower prices could reduce proceeds to the Trust and cash distributions to Trust unitholders.

The Trust’s reserves and monthly cash distributions are highly dependent upon the prices realized from the sale of oil and natural gas. 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 the Sponsor. These factors include, among others:

- regional, domestic and foreign supply and perceptions of supply of oil and natural gas;

- the level of demand and perceptions of demand for oil and natural gas;

- political conditions or hostilities in oil and natural gas producing regions;
- the armed conflicts between Russia and Ukraine and between Israel and Iran and its proxies and the potential destabilizing effects such conflicts may pose for the global oil and gas markets;
- the actions of OPEC, its members and other oil-producing nations, such as Russia, relating to oil price and production levels, including announcements of potential changes to such levels;
- the levels of production of oil and natural gas of non-OPEC countries;
- anticipated future prices of oil and natural gas and other commodities;
- weather conditions and seasonal trends;
- technological advances affecting energy consumption and energy supply;
- U.S. and worldwide economic conditions;
- trade barriers and tariffs;
- the occurrence or threat of epidemic or pandemic diseases or other public health event or any government response to such occurrence or threat;
- the price and availability of alternative fuels;
- the proximity, capacity, cost and availability of gathering and transportation facilities;
- the volatility and uncertainty of regional pricing differentials;
- governmental regulations and taxation;
- energy conservation and environmental measures; and
- acts of force majeure.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. A substantial or extended decline in oil or natural gas prices will reduce profits to which the Trust is entitled and therefore the amount of cash available for distribution to Trust unitholders. A prolonged period of low oil or natural gas prices may ultimately reduce the amount of oil and natural gas that is economically viable to produce from the Underlying Properties. As a result, the operators of the Underlying Properties could determine during periods of low commodity prices to shut-in or curtail production from wells on the Underlying Properties, or even plug and abandon marginal wells that otherwise may have been allowed to continue to produce for a longer period under conditions of higher prices. Specifically, an operator may abandon any well or property if it reasonably believes that the well or property can no longer produce oil or natural gas in commercially paying quantities. This could result in termination of the Net Profits Interest relating to the abandoned well or property.

The Underlying Properties are sensitive to decreasing commodity prices. The commodity price sensitivity is due to a variety of factors that vary from well to well, including the costs associated with water handling and disposal, chemicals, surface equipment maintenance, downhole casing repairs and reservoir pressure maintenance activities that are necessary to maintain production. As a result, decreasing commodity prices may cause the expenses of certain wells to exceed the well’s revenue, in which case the operator may decide to shut-in the well or plug and abandon the well. This scenario could reduce future cash distributions to Trust unitholders. Sustained lower prices of oil and natural gas also could negatively affect the price of the Trust Units and the qualification of the Trust Units to remain listed on the New York Stock Exchange.

The Sponsor has not entered into any hedge contracts relating to oil and natural gas volumes expected to be produced on behalf of the Trust, and the terms of the Conveyance prohibit the Sponsor from entering into new hedging arrangements burdening the Trust. As a result, all production in which the Trust has an interest is unhedged, and the amount of cash available for distribution may be subject to greater fluctuations due to changes in oil and natural gas prices.

Actual reserves and future production may be less than current estimates, which could reduce cash distributions by the Trust and the value of the Trust Units.

The value of the Trust Units and the amount of future cash distributions to the Trust unitholders will depend upon, among other things, the accuracy of the oil and natural gas reserves and future production estimated to be attributable to the Trust's interest in the Underlying Properties. It is not possible to measure underground accumulations of oil and natural gas in an exact way, and estimating reserves is inherently uncertain. Ultimately, actual production and revenues from the Underlying Properties could be materially lower than estimates. Furthermore, direct operating expenses and development expenses relating to the Underlying Properties could be substantially higher than current estimates. Petroleum engineers are required to make subjective estimates of underground accumulations of oil and natural gas based on factors and assumptions that include:

- historical production from the area compared with production rates from other producing areas;
- oil and natural gas prices, production levels, Btu content, production expenses, transportation costs, severance and excise taxes and development expenses;
- the availability of enhanced recovery techniques;
- relationships with landowners, operators, pipeline companies and others; and
- the assumed effect of expected governmental regulation and future tax rates.

Changes in these assumptions and amounts of actual direct operating expenses and development expenses could materially decrease reserve estimates. In addition, the quantities of recovered reserves attributable to the Underlying Properties may decrease in the future as a result of future decreases in the price of oil or natural gas.

The reserve report estimating the Trust's proved reserves, future production and income attributable to the Trust's interests in the Underlying Properties as of December 31, 2024 was prepared, in accordance with applicable regulations, using an average of the NYMEX first-day-of-the-month commodity price during the 12-month period ending on December 31, 2024 as required by the SEC. The applicable prices for 2024 were $75.48 per Bbl of oil and $2.130 per Mcf of natural gas.

The ability or willingness of OPEC and other oil exporting nations to set and maintain production levels has a significant impact on oil and natural gas commodity prices, which could reduce the amount of cash available for distribution to Trust unitholders.

OPEC is an intergovernmental organization that seeks to manage the price and supply of oil on the global energy market. Actions taken by OPEC members, including those taken alongside other oil exporting nations, such as Russia, have a significant impact on global oil supply and pricing. For example, OPEC and certain other oil exporting nations, such as Russia, have previously agreed to take measures, including production cuts, to support crude oil prices OPEC members and other oil exporting nations might not agree to future production cuts or other actions to support and stabilize oil prices, and they may not reduce oil prices or increase production in the future. Uncertainty regarding future actions that OPEC members or other oil exporting countries may take could lead to continued volatility in the price of oil, which could adversely affect the financial condition and economic performance of the operators of the Underlying Properties and may reduce the net proceeds to which the Trust is entitled, which could materially reduce or completely eliminate the amount of cash available for distribution to Trust unitholders.

Third-party operators operate all of the wells on the Underlying Properties; therefore, the Sponsor is not in a position to control the timing of development efforts, the associated costs or the rate of production of the reserves on such properties.

As of December 31, 2024, all of the wells on the Underlying Properties were operated by third-party operators. As a result, the Sponsor has limited ability to exercise influence over, and control the risks or costs associated with, the operations of these properties. The failure of a third-party operator to adequately or efficiently perform operations, a third-party operator's breach of the applicable operating agreements or a third-party operator's failure to act in ways that are in the Sponsor's or the Trust's best interests could reduce production and revenues and therefore, proceeds payable to the Trust and, ultimately, cash available for distribution to Trust unitholders. Further, none of the third-party operators of the Underlying Properties is obligated to undertake any development activities, so any development and production activities will be subject to their reasonable discretion. Therefore, the success and timing of drilling and development activities on properties operated by the third-party operators depend on factors that are largely outside of the Sponsor's control, including:

- the timing and amount of capital expenditures, which could be significantly more than anticipated;
- the availability of suitable drilling equipment, production and transportation infrastructure and qualified operating personnel;
- the third-party operators' expertise, operating efficiency and financial resources;
- approval of other participants in drilling wells;
- the selection of technology;
- the selection of counterparties for the sale of production; and
- the rate of production of the reserves.

The third-party operators may elect not to undertake development activities, or may undertake such activities in an unanticipated fashion, which may result in significant fluctuations in capital expenditures and amounts available for distribution to Trust unitholders.

In addition, disagreements may arise between one or more of the operators, on the one hand, and the Sponsor, on the other hand, regarding the associated costs of the Underlying Properties for which the Sponsor may be responsible, a portion of which may be attributable to the Trust, to the extent of the Trust's interest in the Underlying Properties. Such disagreements could result in litigation or other legal proceedings, which could reduce cash available for distribution to Trust unitholders.

Developing oil and natural gas wells and producing oil and natural gas are costly and high-risk activities with many uncertainties that could adversely affect future production from the Underlying Properties. Any delays, reductions or cancellations in development and producing activities could decrease revenues that are available for distribution to Trust unitholders.

The process of developing oil and natural gas wells and producing oil and natural gas on the Underlying Properties is subject to numerous risks beyond the control of the Trust, the Sponsor or the third-party operators, including risks that could delay the operators' current drilling or production schedule and the risk that drilling will not result in commercially viable oil or natural gas production. The ability of the operators to carry out operations or to finance planned development expenses could be materially and adversely affected by any factor that may curtail, delay, reduce or cancel development and production, including:

- declines in oil or natural gas prices;
- delays imposed by or resulting from compliance with environmental and other governmental or regulatory requirements, including permitting;
- unusual or unexpected geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;

- lack of available gathering, transportation and processing facilities, including availability on commercially reasonable terms, or delays in construction of gathering facilities;
- lack of available capacity on interconnecting transmission pipelines;
- equipment malfunctions, failures or accidents;
- unexpected operational events and drilling conditions;
- market limitations for oil or natural gas;
- pipe or cement failures;
- casing collapses;
- lost or damaged drilling and service tools;
- loss of drilling fluid circulation;
- uncontrollable flows of oil and natural gas, inert gas, water or drilling fluids;
- blowouts, explosions, fires and natural disasters;
- environmental hazards, such as oil and natural gas leaks, pipeline ruptures and discharges of toxic gases or other pollutants into the surface or subsurface environment;
- adverse weather conditions; and
- oil or natural gas property title problems or legal disputes regarding leasehold rights.

If planned operations, including drilling of development wells, are delayed or cancelled, or if existing wells or development wells experience production below anticipated levels due to one or more of the foregoing factors or for any other reason, future distributions to Trust unitholders may be reduced. If an operator incurs increased costs due to one or more of the foregoing factors or for any other reason and is unable to recover such costs from insurance, future distributions to Trust unitholders may be reduced.

Shortages of equipment, services and qualified personnel could increase costs of developing and operating the Underlying Properties and reduce the amount of cash available for distribution to Trust unitholders.

The demand for qualified and experienced personnel to conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Historically, there have been shortages of drilling rigs and other equipment as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher oil and natural gas prices generally stimulate demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. Shortages of field personnel and equipment or price increases could hinder the ability of the operators of the Underlying Properties to conduct the operations that they currently have planned for the Underlying Properties, which would reduce the amount of cash received by the Trust and available for distribution to Trust unitholders.

The amount of cash available for distribution by the Trust depends in part on access to and operation of gathering, transportation and processing facilities. Any limitation in the availability of those facilities could interfere with sales of oil and natural gas production from the Underlying Properties.

The amount of oil and natural gas that may be produced and sold from a well is subject to curtailment in certain circumstances, such as by reason of weather conditions, pipeline interruptions due to scheduled and unscheduled maintenance, failure of tendered oil and natural gas to meet quality specifications of gathering lines or downstream transporters, excessive line pressure which prevents delivery, physical damage to the gathering system or transportation system or lack of contracted capacity on such systems. The curtailments may vary from a few days to several months. In many cases, the operators of the Underlying Properties receive only limited notice, if any, as to when production will be curtailed and the duration of such curtailments. If the operators of the Underlying Properties are forced to reduce production due to such a curtailment, the revenues of the Trust and the amount of cash distributions to the Trust unitholders similarly would be reduced due to the reduction of profits from the sale of production.

Adverse developments in Texas, Louisiana or New Mexico could adversely impact the results of operations and cash flows of the Underlying Properties and reduce the amount of cash available for distribution to Trust unitholders.

The operations of the Underlying Properties are focused on the production and development of oil and natural gas within the states of Texas, Louisiana and New Mexico. As a result, the results of operations and cash flows of the Underlying Properties depend upon continuing operations in these areas. This concentration could disproportionately expose the Trust's interests to operational and regulatory risk in these areas. Due to the lack of geographic diversification, adverse developments in exploration and production of oil and natural gas in any of these areas of operation could have a significantly greater impact on the results of operations and cash flows of the Underlying Properties than if the operations were more diversified.

FINANCIAL RISKS

The Trust Units may lose value as a result of title deficiencies with respect to the Underlying Properties.

Enduro acquired the Underlying Properties through various acquisitions in late 2010 and early 2011. The Sponsor acquired Enduro's interests in the Underlying Properties pursuant to the Sale Transaction that closed in August 2018. The existence of a material title deficiency with respect to the Underlying Properties could reduce the value of a property or render it worthless, thus adversely affecting the Net Profits Interest and the distributions to Trust unitholders. The Sponsor does not obtain title insurance covering mineral leaseholds, and the Sponsor's failure to cure any title defects may cause the Sponsor to lose its rights to production from the Underlying Properties. If a material title problem were to arise, net profits available for distribution to Trust unitholders, and the value of the Trust Units, may be reduced.

The oil and natural gas reserves attributable to the Underlying Properties are depleting assets and production from those reserves will diminish over time. Furthermore, because the Trust is precluded from acquiring other oil and natural gas properties or net profits interests to replace the depleting assets and production, proceeds to the Trust and cash distributions to Trust unitholders will decrease over time.

The net profits payable to the Trust attributable to the Net Profits Interest are derived from the sale of production of oil and natural gas from the Underlying Properties. The oil and natural gas reserves attributable to the Underlying Properties are depleting assets, which means that the reserves and the quantity of oil and natural gas produced from the Underlying Properties will decline over time.

Future maintenance projects on the Underlying Properties may affect the quantity of proved reserves that can be economically produced from wells on the Underlying Properties. The timing and size of these projects will depend on, among other factors, the market prices of oil and natural gas. Neither the Sponsor nor, to the Sponsor's knowledge, the third-party operators have a contractual obligation to develop or otherwise pay development expenses on the Underlying Properties in the future. Furthermore, with respect to properties for which the Sponsor is not designated as the operator, the Sponsor has limited control over the timing or amount of those development expenses. The Sponsor also has the right to non-consent and not participate in the development expenses on properties for which it is not the operator, in which case the Sponsor and the Trust will not receive the production resulting from such development expenses. If the operators of the Underlying Properties do not implement maintenance projects when warranted, the future rate of production decline of proved reserves may be higher than the rate currently expected by the Sponsor or estimated in the reserve report.

The Trust Agreement provides that the Trust's activities are limited to owning the Net Profits Interest and any activity reasonably related to such ownership, including activities required or permitted by the terms of the Conveyance related to the Net Profits Interest. As a result, the Trust is not permitted to acquire other oil and natural gas properties or net profits interests to replace the depleting assets and production attributable to the Net Profits Interest.

Because the net profits payable to the Trust are derived from the sale of depleting assets, the portion of the distributions to Trust unitholders attributable to depletion may be considered to have the effect of a return of capital as opposed to a return on investment. Eventually, the Underlying Properties burdened by the Net Profits Interest may cease to produce in commercially paying quantities and the Trust may, therefore, cease to receive any distributions of net profits therefrom. At that point the value of the Trust Units should be expected to be $0.

An increase in the differential between the price realized by the Sponsor for oil or natural gas produced from the Underlying Properties and the NYMEX or other benchmark price of oil or natural gas could reduce the net profits payable to the Trust and, therefore, the cash distributions by the Trust and the value of the Trust Units.

The prices received for the Sponsor's oil and natural gas production usually fall below the relevant benchmark prices, such as NYMEX, that are used for calculating hedge positions. The difference between the price received and the benchmark price is called a basis differential. The differential may vary significantly due to market conditions, the quality and location of production and other factors. The Sponsor cannot accurately predict oil or natural gas differentials. Increases in the differential between the realized price of oil and natural gas and the benchmark price for oil and natural gas could reduce the profits to the Trust, the cash distributions by the Trust and the value of the Trust Units.

Higher production and development costs and expenses related to the Underlying Properties and other costs and expenses incurred by the Trust, without concurrent increases in revenue, will reduce the amount of cash available for distribution to Trust unitholders.

The Trust indirectly bears an 80% share of all costs and expenses related to the Underlying Properties, such as direct operating and development expenses, which reduces the amount of cash received by the Trust and thereafter distributable to Trust unitholders. Accordingly, higher costs and expenses related to the Underlying Properties will directly decrease the amount of cash received by the Trust in respect of its Net Profits Interest. Historical costs may not be indicative of future costs. For example, the third-party operators may in the future propose additional drilling projects that significantly increase the capital expenditures associated with the Underlying Properties, which could reduce cash available for distribution by the Trust. In addition, cash available for distribution by the Trust will be further reduced by the Trust's general and administrative expenses.

If direct operating and development expenses on the Underlying Properties, together with the other costs, exceed gross profits of production from the Underlying Properties, the Trust will not receive net profits from those properties until future gross profits from production exceed the total of the excess costs, plus accrued interest at the prime rate. If the Trust does not receive net profits pursuant to the Net Profits Interest, or if such net profits are reduced, the Trust will not be able to distribute cash to the Trust unitholders, or such cash distributions will be reduced, respectively. Development activities may not generate sufficient additional revenue to repay the costs.

The Trust has established a cash reserve for contingent liabilities and to pay expenses in accordance with the Trust Agreement, which would reduce net profits payable to the Trust and distributions to Trust unitholders.

The Trust's source of capital is the cash flows from the Net Profits Interest. Pursuant to the Trust Agreement, the Trust may establish a cash reserve through the withholding of cash for contingent liabilities and to pay expenses, which will reduce the amount of cash otherwise available for distribution to Trust unitholders.

In November 2021, the Trustee notified the Sponsor of the Trustee's intent to build a cash reserve for the payment of future known, anticipated or contingent expenses or liabilities of the Trust. From February 2022 through March 2023, the Trustee withheld $37,833, and commencing with the distribution to Trust unitholders paid in April 2023 has been withholding and, in the future, intends to withhold $50,000, from the funds otherwise available for distribution each month to gradually build a cash reserve of approximately $2.3 million. As of December 31, 2024, the cumulative cash reserve balance was $1,241,386. The Trustee may increase or decrease the targeted amount at any time, and may increase or decrease the rate at which it is withholding funds to build the cash reserve at any time, without advance notice to the Trust unitholders.

The amount of cash available for distribution by the Trust could be reduced by expenses caused by uninsured claims.

The Sponsor maintains insurance coverage against potential losses that it believes is customary in its industry. The Sponsor currently maintains general liability insurance and excess liability coverage. The Sponsor's excess liability coverage and general liability insurance do not have deductibles. The general liability insurance covers the Sponsor and its subsidiaries for legal and contractual liabilities arising out of bodily injury or property damage, including any resulting loss of use to third parties, and for sudden and accidental pollution or environmental liability, while the excess liability coverage is in addition to and triggered if the general liability per occurrence limit is reached. In addition, the Sponsor maintains control of well insurance with per occurrence limits depending on the status of the well and deductibles consistent with industry standards. The Sponsor's general liability insurance and excess liability policies do not provide coverage with respect to legal and contractual liabilities of the Trust, and the Trust does not maintain such coverage since it is passive in nature and does not have any ability to influence the Sponsor or control the operations or development of the Underlying Properties.

The Sponsor does not currently have any insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations, other than its general liability and excess liability insurance policies that may cover third-party claims related to hydraulic fracturing operations in accordance with, and subject to, the terms of such policies. These policies may not cover fines, penalties or costs and expenses related to government-mandated cleanup of pollution. In addition, these policies do not provide coverage for all liabilities, and the insurance coverage may not be adequate to cover claims that may arise; moreover, the Sponsor may not be able to maintain adequate insurance at rates it considers reasonable. The occurrence of an event not fully covered by insurance could result in a significant decrease in the amount of cash available for distribution by the Trust. The Trust does not maintain any type of insurance against any of the risks of conducting oil and gas exploration and production, hydraulic fracturing operations, or related activities.

The Sponsor's ability to perform its obligations to the Trust could be limited by restrictions under its debt agreements.

The Sponsor has various contractual obligations to the Trust under the Trust Agreement and Conveyance. Restrictions under the Sponsor's debt agreements, including certain covenants, financial ratios and tests, could impair its ability to fulfill its obligations to the Trust. The requirement that the Sponsor comply with these restrictive covenants and financial ratios and tests may materially adversely affect its ability to react to changes in market conditions, take advantage of business opportunities it believes to be desirable, obtain future financing, fund needed capital expenditures or withstand a continuing or future downturn in its business which may, in turn, impair the Sponsor's operations and its ability to perform its obligations to the Trust under the Trust Agreement and Conveyance. If the Sponsor is unable to perform its obligations to the Trust under the Trust Agreement or Conveyance, it could have a material adverse effect on the Trust.

The bankruptcy of the Sponsor or any of the third-party operators could impede the operation of the wells and the development of the proved undeveloped reserves.

The value of the Net Profits Interest and the Trust's ultimate cash available for distribution is highly dependent on the financial condition of the operators of the Underlying Properties. None of the operators of the Underlying Properties, including the Sponsor, has agreed with the Trust to maintain a certain net worth or to be restricted by other similar covenants.

The ability to develop and operate the Underlying Properties depends on the future financial condition and economic performance and access to capital of the operators of those properties, which in turn will depend upon the supply and demand for oil and natural gas, prevailing economic conditions and financial, business and other factors, many of which are beyond the control of the Sponsor and the third party operators. Reduced demand for crude oil in the global market could have a negative impact on the financial condition and economic performance of one or more of the operators of the Underlying Properties. The Sponsor is not a reporting company and is not required to file periodic reports with the SEC pursuant to the Exchange Act. Therefore, Trust unitholders do not have access to financial information about the Sponsor.

In the event of any future bankruptcy of any operator of the Underlying Properties, the working interest owners in the affected properties will have to seek a new party to perform the development and the operations of the affected wells. The working interest owners may not be able to find a replacement driller or operator, and they may not be able to enter into a new agreement with such replacement party on favorable terms within a reasonable period. As a result, such a bankruptcy may result in reduced production from the reserves and decreased distributions to Trust unitholders, and could adversely affect the value of the Net Profits Interest.

In the event of the bankruptcy of the Sponsor, if a court were to hold that the Net Profits Interest was part of the bankruptcy estate, the Trust may be treated as an unsecured creditor with respect to the Net Profits Interest attributable to properties in Louisiana and New Mexico.

The Sponsor and the Trust believe that, in a bankruptcy of the Sponsor, the Net Profits Interest would be viewed as a separate property interest under Texas law and, as such, outside of the Sponsor's bankruptcy estate. However, if the bankruptcy court were to hold otherwise, or if Louisiana or New Mexico law were held to be applicable, the Net Profits Interest might be considered an asset of the bankruptcy estate and used to satisfy obligations to creditors of the Sponsor, in which case the Trust would be an unsecured creditor of the Sponsor at risk of losing the entire value of the Net Profits Interest to senior creditors.

RISKS RELATED TO THE STRUCTURE OF THE TRUST

The Trust is passive in nature and neither the Trustee nor the Trust unitholders have any ability to influence the Sponsor or control the operations or development of the Underlying Properties.

The Trust Units are a passive investment that entitles the Trust unitholders to only receive cash distributions derived from the Net Profits Interest. Trust unitholders have no voting rights with respect to the Sponsor and, therefore, have no managerial, contractual or other ability to influence the Sponsor's or the third-party operators' activities or the operations of the Underlying Properties. Oil and natural gas properties are typically managed pursuant to an operating agreement among the working interest owners of oil and natural gas properties. Third party operators operate substantially all of the wells on the Underlying Properties. The typical operating agreement contains procedures whereby the owners of the working interests in the property designate one of the interest owners to be the operator of the property. Under these arrangements, the operator is typically responsible for making all decisions relating to drilling activities, sale of production, compliance with regulatory requirements and other matters that affect the property. Neither the Trustee nor the Trust unitholders have any contractual ability to influence or control the field operations of, sale of oil or natural gas from, or any future development of, the Underlying Properties. The current operators developing the Underlying Properties are under no obligations to continue operations on the Underlying Properties. Neither the Trustee nor the Trust unitholders have the right to replace an operator.

Subject to specified limitations, the Sponsor may transfer all or a portion of the Underlying Properties at any time without Trust unitholder consent.

The Sponsor at any time may transfer all or part of the Underlying Properties, subject to and burdened by the Net Profits Interest, and may, along with the third-party operators, abandon individual wells or properties reasonably believed to be not economically viable. Trust unitholders will not be entitled to vote on any transfer or abandonment of the Underlying Properties, and the Trust will not receive any net proceeds from any such transfer, except in the limited circumstances when the Net Profits Interest is released in connection with such transfer, in which case the Trust will receive an amount equal to the fair market value (net of sales costs) of the Net Profits Interest released. Following any sale or transfer of any of the Underlying Properties, if the Net Profits Interest is not released in connection with such sale or transfer, the Net Profits Interest will continue to burden the transferred property and net profits attributable to such property will be calculated as part of the computation of net profits. The Sponsor may delegate to the transferee responsibility for all of the Sponsor's obligations relating to the Net Profits Interest on the portion of the Underlying Properties transferred.

In addition, the Sponsor may, without the consent of the Trust unitholders, require the Trustee to release the Net Profits Interest associated with any lease that accounts for no more than 0.25% of the total production from the Underlying Properties in the prior 12 months, provided that the Net Profits Interest covered by such releases cannot exceed, during any 12-month period, an aggregate fair market value to the Trust of $500,000. These releases may be made only in connection with a sale by the Sponsor to a non-affiliate of the relevant Underlying Properties and are conditioned upon an amount equal to the fair market value of such Net Profits Interest being treated as an offset amount against costs and expenses. For example, in May 2023, the Sponsor sold approximately $0.3 million in non-producing, non-cash flowing acreage to a private oil company, free and clear of the Net Profits Interest, as permitted under the Trust Agreement.

The third-party operators and the Sponsor may enter into farm-out, operating, participation and other similar agreements to develop the property without the consent or approval of the Trustee or any Trust unitholder.

Under certain circumstances, the Trustee must sell the Net Profits Interest and dissolve the Trust prior to the expected termination of the Trust. As a result, Trust unitholders may not recover their investment.

The Trustee must sell the Net Profits Interest and dissolve the Trust if the holders of at least 75% of the outstanding Trust Units approve the sale or vote to dissolve the Trust. The Trustee must also sell the Net Profits Interest and dissolve the Trust if the annual cash proceeds received by the Trust attributable to the Net Profits Interest are less than $2 million for each of any two consecutive years. The net profits of any such sale will be distributed to the Trust unitholders; however, Trust unitholders may not recover their investment in the Trust Units.

Conflicts of interest could arise between the Sponsor and its affiliates, on the one hand, and the Trust and the Trust unitholders, on the other hand.

As working interest owners in, and the operators of certain wells on, the Underlying Properties, the Sponsor and its affiliates could have interests that conflict with the interests of the Trust and the Trust unitholders. For example:

- The Sponsor’s interests may conflict with those of the Trust and the Trust unitholders in situations involving the development, maintenance, operation or abandonment of certain wells on the Underlying Properties for which the Sponsor acts as the operator. The Sponsor also may make decisions with respect to development expenses that adversely affect the Underlying Properties. These decisions include reducing development expenses on properties for which the Sponsor acts as the operator, which could cause oil and natural gas production to decline at a faster rate and thereby result in lower cash distributions by the Trust in the future.

- The Sponsor may sell some or all the Underlying Properties without taking into consideration the interests of the Trust unitholders. Such sales may not be in the best interests of the Trust unitholders. These purchasers may lack the Sponsor’s experience or its creditworthiness. The Sponsor also has the right, under certain circumstances, to cause the Trustee to release all or a portion of the Net Profits Interest in connection with a sale of a portion of the Underlying Properties to which such Net Profits Interest relates. In such an event, the Trust is entitled to receive the fair value (net of sales costs) of the Net Profits Interest released.

- The Sponsor may sell its Trust Units without considering the effects such sale may have on Trust Unit prices or on the Trust itself. Additionally, the Sponsor can vote its Trust Units in its sole discretion without considering the interests of the other Trust unitholders. The Sponsor is not a fiduciary with respect to the Trust unitholders or the Trust and does not owe any fiduciary duties or liabilities to the Trust unitholders or the Trust.

The Trust is administered by a Trustee who cannot be replaced except by a majority vote of the Trust unitholders at a special meeting, which may make it difficult for Trust unitholders to remove or replace the Trustee.

The affairs of the Trust are administered by the Trustee. 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. The Trust Agreement provides that the Trustee may only be removed and replaced by the holders of a majority of the Trust Units present in person or by proxy at a meeting of such holders where a quorum is present, including Trust Units held by the Sponsor, called by either the Trustee or the holders of not less than 10% of the outstanding Trust Units. As a result, it will be difficult for public Trust unitholders to remove or replace the Trustee without the cooperation of holders of a significant percentage of total Trust Units.

Trust unitholders have limited ability to enforce provisions of the Conveyance, and the Sponsor's liability to the Trust is limited.

The Trust Agreement permits the Trustee to sue the Sponsor or any other future owner of the Underlying Properties to enforce the terms of the Conveyance. If the Trustee does not take appropriate action to enforce provisions of the Conveyance, Trust unitholders' recourse would be limited to bringing a lawsuit against the Trustee to compel the Trustee to take specified actions. The Trust Agreement expressly limits a Trust unitholder's ability to directly sue the Sponsor or any other third party other than the Trustee. As a result, Trust unitholders will not be able to sue the Sponsor or any future owner of the Underlying Properties to enforce these rights. Furthermore, the Conveyance provides that, except as set forth in the Conveyance, the Sponsor will not be liable to the Trust for the manner in which it performs its duties in operating the Underlying Properties as long as it acts without gross negligence or willful misconduct. In addition, the Trust Agreement provides that, to the fullest extent permitted by law, the Sponsor is not subject to fiduciary duties or liable for conflicts of interest principles.

Financial information of the Trust is not prepared in accordance with 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 accounting principles generally accepted in the United States, or GAAP. Although this basis of accounting is permitted for royalty trusts by the SEC, the financial statements of the Trust differ from GAAP financial statements because revenues are not accrued in the month of production, expenses are recorded when paid and not when incurred, and cash reserves may be established for specified contingencies and deducted which could not be accrued in GAAP financial statements.

The Trust is a smaller reporting company and benefits from certain reduced governance and disclosure requirements, including that the Trust's independent registered public accounting firm is not required to attest to the effectiveness of the Trust's internal control over financial reporting. The Trust cannot be certain if the omission of reduced disclosure requirements applicable to smaller reporting companies will make the Trust Units less attractive to investors.

Currently, the Trust is a "smaller reporting company," meaning that the outstanding Trust Units held by nonaffiliates had a value of less than $250 million at the end of the Trust's most recently completed second fiscal quarter. As a smaller reporting company, the Trust is not required to comply with the auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act, meaning the Trust's auditors are not required to attest to the effectiveness of the Trust's internal control over financial reporting. As a result, investors and others may be less comfortable with the effectiveness of the Trust's internal controls and the risk that material weaknesses or other deficiencies in internal controls go undetected may increase. In addition, as a smaller reporting company, the Trust takes advantage of its ability to provide certain other less comprehensive disclosures in its SEC filings, including, among other things, providing only two years of audited financial statements in annual reports. Consequently, it may be more challenging for investors to analyze the Trust's results of operations and financial prospects, as the information the Trust provides to Trust unitholders may be different from what one might receive from other public companies in which one holds shares. As a smaller reporting company, the Trust is not required to provide this information.

RISKS RELATED TO OWNERSHIP OF THE TRUST UNITS

If the Trust cannot meet the New York Stock Exchange continued listing requirements, the NYSE may delist the Trust Units.

Under the continued listing requirements of the NYSE, a company will be considered to be out of compliance with the exchange's minimum price requirement if the company's average closing price over a consecutive 30 trading day period ("Average Closing Price") is less than $1.00 (the "Minimum Price Requirement"). Under NYSE rules, a company that is out of compliance with the Minimum Price Requirement has a cure period of six months to regain compliance if it notifies the NYSE within 10 business days of receiving a deficiency notice of its intention to cure the deficiency. A company may regain compliance if on the last trading day of any calendar month during the cure period the company has a closing share price of at least $1.00 and an average closing share price of at least $1.00 over the 30-trading-day period ending on the last trading day of that month. If at the expiration of the cure period, both a $1.00 closing share price on the last trading day of the cure period and a $1.00 average closing share price over the 30-trading-day period ending on the last trading day of the cure period are not attained, the NYSE will commence suspension and delisting procedures. If delisted by the NYSE, a company's shares may be transferred to the over-the-counter ("OTC") market, a significantly more limited market than the NYSE, which could affect the market price, trading volume, liquidity and resale price of such shares. Securities that trade on the OTC markets also typically experience more volatility compared to securities that trade on a national securities exchange. During the cure period, the company's shares would continue to trade on the NYSE, subject to compliance with other continued listing requirements. The Trust has fallen out of compliance with the Minimum Price Requirement in the past, most recently in 2020, and although the Trust was able to regain compliance within the applicable grace period, the Trust may be unable to maintain compliance in the future and could again become subject to the NYSE delisting procedures. Over the 30-day trading period that ended March 18, 2025, the closing price of the Trust Units on the NYSE ranged from a high of $1.55 on March 12, 2025 to a low of $1.395 on February 13, 2025.

The Sponsor may sell Trust Units in the public or private markets, and such sales could have an adverse impact on the trading price of the Trust Units.

As of March 18, 2025, the Sponsor holds an aggregate of 7,363,961 Trust Units. The Sponsor may sell Trust Units in the public or private markets, and any such sales could have an adverse impact on the price of the Trust Units. On June 22, 2022, pursuant to the Registration Rights Agreement between the Trust and the Sponsor, the Trust filed a registration statement on Form S-3 registering the offering by the Sponsor of 8,600,000 Trust Units. The registration statement was declared effective on July 7, 2022. Since then, the Sponsor has sold approximately 1.2 million Trust Units under the Registration Statement pursuant to a Rule 10b5-1 trading plan adopted in accordance with Rule 10b5-1 of the Exchange Act.

The trading price for the Trust Units may not reflect the value of the Net Profits Interest held by the Trust.

The trading price for publicly traded securities similar to the Trust Units tends to be tied to recent and expected levels of cash distributions. The amounts available for distribution by the Trust vary in response to numerous factors outside the control of the Trust, including prevailing prices for sales of oil and natural gas production from the Underlying Properties and the timing and amount of direct operating expenses and development expenses. Consequently, the market price for the Trust Units may not necessarily be indicative of the value that the Trust would realize if it sold the Net Profits Interest to a third-party buyer. In addition, the market price may not necessarily reflect the fact that since the assets of the Trust are depleting assets, a portion of each cash distribution paid with respect to the Trust Units should be considered by investors as a return of capital, with the remainder being considered as a return on investment. As a result, distributions made to a Trust unitholder over the life of these depleting assets may not equal or exceed the purchase price paid by the Trust unitholder.

Courts outside of Delaware may not recognize the limited liability of the Trust unitholders provided under Delaware law.

Under the Delaware Statutory Trust Act, Trust unitholders will be entitled to the same limitation of personal liability extended to stockholders of corporations for profit under the General Corporation Law of the State of Delaware. The courts in jurisdictions outside of Delaware, however, might not give effect to such limitation.

LEGAL, ENVIRONMENTAL AND REGULATORY RISKS

The operations of the Underlying Properties are subject to environmental laws and regulations that could adversely affect the cost, manner or feasibility of conducting operations on them or result in significant costs and liabilities, which could reduce the amount of cash available for distribution to Trust unitholders.

The oil and natural gas exploration and production operations on the Underlying Properties are subject to stringent and comprehensive federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations that apply to the operations on the Underlying Properties, including the requirement to obtain a permit before conducting drilling, waste disposal or other regulated activities; the restriction of types, quantities and concentrations of materials that can be released into the environment; restrictions on water withdrawal and use; the incurrence of significant development expenses to install pollution or safety-related controls at the operated facilities; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and the imposition of substantial liabilities for pollution resulting from operations.

For example, the EPA has published regulations that impose more stringent emissions control requirements for oil and gas development and production operations, which may require the Sponsor, its operators, or third-party contractors to incur additional expenses to control air emissions from current operations and during new well developments by installing emissions control technologies and adhering to a variety of work practice and other requirements. In addition, in 2012 and 2016, the EPA adopted federal New Source Performance Standards (“NSPS”) that require the reduction of volatile organic compound and sulfur dioxide emissions from certain fractured and refractured natural gas wells for which well completion operations are conducted and further require that most wells use reduced emission completions, also known as “green completions.” These regulations also establish specific requirements limiting emissions from production-related wet seal and reciprocating compressors, pumps, and from pneumatic controllers and storage vessels, and for equipment leaks. These NSPS apply to sources that are newly constructed or modified after the rules’ applicability dates. More recently, in December 2023 the EPA adopted a final rule that will directly regulate volatile organic compound and methane emissions from new oil and gas sources and will require further reductions in emissions through its regulation of flaring, compressors, pumps, storage vessels, process controllers, well completions and liquids unloading, and equipment leaks. At the same time, the EPA adopted emissions guidelines that will apply to existing oil and gas sources and that require reductions in volatile organic compound and methane emissions that are largely equivalent to the requirements for new sources. The existing source emissions guidelines are to be implemented through state plans, with expected compliance dates for existing sources arriving in 2029.

Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions. Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties; the imposition of investigatory or remedial obligations; and the issuance of injunctions limiting or preventing some or all of the operations on the Underlying Properties. Furthermore, the inability to comply with environmental laws and regulations in a cost-effective manner, such as removal and disposal of produced water and other generated oil and gas wastes, could impair the operators’ ability to produce oil and natural gas commercially from the Underlying Properties, which would reduce profits attributable to the Net Profits Interest.

There is inherent risk of incurring significant environmental costs and liabilities in the operations on the Underlying Properties as a result of the handling of petroleum hydrocarbons and wastes, air emissions and wastewater discharges related to operations, and historical industry operations and waste disposal practices. Under certain environmental laws and regulations, the operators could be subject to joint and several strict liability for the removal or remediation of previously released materials or property contamination regardless of whether such operators were responsible for the release or contamination or whether the operations were in compliance with all applicable laws at the time those actions were taken. Private parties, including the owners of properties upon which wells are drilled and facilities where petroleum hydrocarbons or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. In addition, the risk of accidental spills or releases could expose the operators of the Underlying Properties to significant liabilities that could have a material adverse effect on the operators' businesses, financial condition and results of operations and could reduce the amount of cash available for distribution to Trust unitholders. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly operational control requirements or waste handling, storage, transport, disposal or cleanup requirements could require the operators of the Underlying Properties to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on their results of operations, competitive position or financial condition.

The Trust will indirectly bear 80% of all costs and expenses paid by the Sponsor, including those related to environmental compliance and liabilities associated with the Underlying Properties, including costs and liabilities resulting from conditions that existed prior to the Sponsor's acquisition of the Underlying Properties unless such costs and expenses result from the operator's negligence or misconduct. In addition, as a result of the increased cost of compliance, the operators of the Underlying Properties may decide to discontinue drilling.

Neither the Sponsor nor the Trust is generally entitled to, nor required to provide, indemnity to third party operators with respect to pollution liability and associated environmental remediation costs. However, the Sponsor may be required to provide, and may be entitled to, indemnity from third party operators with respect to such liabilities and costs in the event of the other party's gross negligence or misconduct. In addition, the Sponsor has agreed to assume certain environmental liabilities of prior owners of the Underlying Properties in connection with the purchase thereof.

The operations on the Underlying Properties are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting operations on them or expose the operator to significant liabilities, which could reduce the amount of cash available for distribution to Trust unitholders.

The production and development operations on the Underlying Properties are subject to complex and stringent laws and regulations. To conduct their operations in compliance with these laws and regulations, the operators of the Underlying Properties must obtain and maintain numerous permits, drilling bonds, approvals and certificates from various federal, state and local governmental authorities and engage in extensive reporting. The operators of the Underlying Properties may incur substantial costs and experience delays in order to maintain compliance with these existing laws and regulations, and the Trust will bear an 80% share of these costs. In addition, the operators' costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to their operations. Such costs could have a material adverse effect on the operators' business, financial condition and results of operations and reduce the amount of cash received by the Trust in respect of the Net Profits Interest. The operators of the Underlying Properties must also comply with laws and regulations prohibiting fraud and market manipulations in energy markets. To the extent the operators of the Underlying Properties are shippers on interstate pipelines, they must comply with the tariffs of such pipelines and with federal policies related to the use of interstate capacity, and such compliance costs will be borne in part by the Trust.

Laws and regulations governing exploration and production may also affect production levels. The operators of the Underlying Properties are required to comply with federal and state laws and regulations governing conservation matters, including: provisions related to the unitization or pooling of the oil and natural gas properties; the establishment of maximum rates of production from wells; the spacing of wells; the plugging and abandonment of wells; and the removal of related production equipment. Additionally, state and federal regulatory authorities may expand or alter applicable pipeline safety laws and regulations, compliance with which may require increase capital costs on the part of the operators and third party downstream natural gas transporters. These and other laws and regulations can limit the amount of oil and natural gas the operators can produce from their wells, limit the number of wells they can drill, or limit the locations at which they can conduct drilling operations, which in turn could negatively impact Trust distributions, estimated and actual future net revenues to the Trust and estimates of reserves attributable to the Trust's interests.

New laws or regulations, or changes to existing laws or regulations, may unfavorably impact the operators of the Underlying Properties and result in increased operating costs or have a material adverse effect on their financial condition and results of operations and reduce the amount of cash received by the Trust. For example, Congress is currently considering legislation that, if adopted in its proposed form, would subject companies involved in oil and natural gas exploration and production activities to, among other items, additional regulation of and restrictions on hydraulic fracturing of wells, the elimination of certain U.S. federal tax incentives and deductions available to oil and natural gas exploration and production activities and the prohibition or additional regulation of private energy commodity derivative and hedging activities. These and other potential regulations could increase the operating costs of the Underlying Properties, reduce the operators' liquidity, delay the operators' operations or otherwise alter the way the operators conduct their business, any of which could have a material adverse effect on the Trust and the amount of cash available for distribution to Trust unitholders.

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

In response to its 2009 finding that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") may present an endangerment to public health and the environment, the EPA has issued regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. These regulations include limits on tailpipe emissions from motor vehicles, preconstruction and operating permit requirements for certain large stationary sources, and methane emissions standards for certain new, modified and reconstructed oil and gas sources – as well as the EPA's methane emissions guidelines for existing oil and gas sources that were adopted in 2024. The EPA also has adopted rules requiring the reporting of GHG emissions from specified large greenhouse gas emission sources in the United States, as well as certain onshore oil and natural gas production facilities, on an annual basis.

On January 20, 2025, President Trump announced the withdrawal of the United States from the Paris Climate Agreement. President Trump also issued an executive order directing the EPA to review the legality and continuing applicability of its 2009 GHG endangerment finding. The outcome of that review is not currently known; however, it has the potential to eliminate the basis for the EPA's regulation of GHGs under the CAA.

The EPA has established GHG standards for oil and gas sources based on its endangerment finding. In 2024, the EPA adopted a final rule that will directly regulate volatile organic compound and methane emissions from new oil and gas sources and will require further emissions reductions through its regulation of flaring, compressors, pumps, storage vessels, process controllers, well completions and liquids unloading, and equipment leaks. At the same time, the EPA adopted emissions guidelines that will apply to existing oil and gas sources and that require reductions in volatile organic compound and methane emissions that are largely equivalent to the requirements for new sources. The existing source emissions guidelines are to be implemented through state plans, with expected compliance dates for existing sources arriving in 2029.

The Inflation Reduction Act of 2022 ("IRA") included new CAA section 136(c) directing EPA to collect the Waste Emissions Charge ("WEC") from facilities in the oil and gas sector that report more than 25,000 tons of carbon dioxide equivalent emissions in a calendar year. The charge will first apply to methane emissions from calendar year 2024. The charge is determined by comparing actual reported methane emissions to statutorily established "methane intensity figures" that are based on gas production or throughput, with a charge assessed for every ton of methane emissions that exceeds the facility's allowable emissions based on the applicable methane intensity figure. The charge will be $900 per ton for 2024 emissions and will increase to $1,200 and then $1,500 per ton in subsequent years. The program includes key exemptions, most notably a regulatory compliance exemption that applies to and exempts the emissions from facilities that are subject to and in complete compliance with the EPA's new or existing source methane requirements. The EPA adopted new rules to implement the WEC program in November 2024; however, the fate of the WEC and the EPA rules implementing the WEC is unclear. In February 2025, the United States House of Representatives and Senate both passed resolutions to repeal the EPA's 2024 WEC rules under the Congressional Review Act ("CRA"), and on March 14, 2025 President Trump signed the resolution repealing those rules under the CRA. In addition, the United States House of Representatives and Senate may be considering amendment or repeal of certain portions of the IRA, including the statutory provisions establishing the WEC.

Additionally, more than one-third of the states have begun taking actions to control and/or reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Although most of the state-level initiatives have to date focused on large sources of GHG emissions, such as coal-fired electric plants, it is possible that smaller sources of emissions could become subject to GHG emission limitations or allowance purchase requirements in the future. For example, the states of Colorado and New Mexico have adopted rules regulating GHGs from the oil and gas industry that are based on the federal standards. In addition, Congress may consider adopting legislation to reduce emissions of greenhouse gases. Any one of these climate change regulatory and legislative initiatives could have a material adverse effect on the Sponsor's business, capital expenditures, financial condition and results of operations.

The adoption and implementation of regulations imposing reporting obligations on, or limiting emissions of GHGs from, the Sponsor's equipment and operations could require the Sponsor to incur costs to reduce emissions of GHGs associated with its operations or could adversely affect demand for the natural gas it produces. Legislation or regulations that may be adopted to address climate change could also affect the markets for the Sponsor's products by making its products less desirable than competing sources of energy. To the extent that its products are competing with lower GHG-emitting energy, the Sponsor's products may become less desirable in the market with more stringent limitations on greenhouse gas emissions. The Sponsor cannot predict with any certainty at this time how these possibilities may affect its operations.

In addition, new and emerging regulatory initiatives in the U.S. related to climate change could adversely affect the Trust. In March 2024, the SEC issued a final rule regarding the enhancement and standardization of mandatory climate-related disclosures for investors. The final rule mandates extensive disclosure of climate-related data, risks, and opportunities, including financial impacts, physical and transition risks, related governance and strategy and greenhouse gas emissions, for certain public companies. Compliance with the final rule may result in increased legal, accounting and financial compliance costs, make some activities more difficult, time-consuming and costly, and place strain on the personnel, systems and resources of the Sponsor or the Trust or both. The SEC's climate disclosure requirements may change under the Trump Administration. In February 2025, the acting SEC Chair issued a statement that the SEC would not defend the 2024 disclosure rule in court and that the SEC would revisit the 2024 rule. The outcome of the SEC's review may result in changes to SEC climate-related disclosure requirements, but the outcome of that review is uncertain. Even in the absence of federal requirements, however, some states have adopted climate disclosure laws or rules that are not affected by the SEC's review.

Finally, some scientists have theorized that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such significant physical effects were to occur, they could have an adverse effect on the Sponsor's assets and operations and cause the Sponsor to incur costs in preparing for and responding to them. Additionally, energy needs could increase or decrease as a result of extreme weather conditions, depending on the duration and magnitude of those conditions.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays as well as adversely affect the services of the operators of the Underlying Properties.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. However, several federal and local agencies have also adopted, or are considering adopting, regulations that could further restrict or prohibit hydraulic fracturing in certain circumstances, impose more stringent operating standards and/or require the disclosure of the composition of hydraulic fracturing fluids. See "Item 1 Business — Environmental Matters and Regulation — Hydraulic fracturing."

Increased regulation and attention given to the hydraulic fracturing process and associated processes could lead to greater opposition to, and litigation concerning, oil and natural gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas, including from developing shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could require the Sponsor or the third party operators to incur development expenses to install and utilize specific equipment, technologies, or work practices to control emissions from their operations, which could reduce the profits available to the Trust and potentially impair the economic development of the Underlying Properties.

Some states have adopted, and other states are considering adopting, regulations that could restrict or impose additional requirements relating to hydraulic fracturing in certain circumstances, including the disclosure of information regarding the substances used in the hydraulic fracturing process. Such federal or state legislation could require the disclosure of chemical constituents used in the fracturing process to state or federal regulatory authorities who could then make such information publicly available. Disclosure of chemicals used in the fracturing process could make it easier for third parties opposing hydraulic fracturing to initiate legal proceedings against producers and service providers based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is regulated at the federal level, the Sponsor's and the third party operators' fracturing activities could become subject to additional permit requirements or operational restrictions and also to associated permitting delays and potential increases in costs. In December 2014, the Governor of New York announced that the state would maintain its moratorium on hydraulic fracturing in the state. Further, some local governments have imposed moratoria on drilling permits within city limits so that local ordinances may be reviewed to assess their adequacy to address such activities. Similar measures might be considered or implemented in the jurisdictions in which the Underlying Properties are located.

If new laws or regulations that significantly restrict or otherwise impact hydraulic fracturing are passed by Congress or adopted in Texas, Louisiana or New Mexico, such legal requirements could make it more difficult or costly for the Sponsor or the third party operators to perform hydraulic fracturing activities and thereby could affect the determination of whether a well is commercially viable. In addition, restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that the operators are ultimately able to produce in commercially paying quantities from the Underlying Properties, and could increase the cycle times and costs to receive permits, delay or possibly preclude receipt of permits in certain areas, impact water usage and wastewater disposal and require air emissions, water usage and chemical additives disclosures.

CYBERSECURITY RISKS

Cyber-attacks or other failures in telecommunications or information technology systems could result in information theft, data corruption and significant disruption of the Sponsor's business operations.

In recent years, the Sponsor has increasingly relied on information technology ("IT") systems and networks in connection with its business activities, including certain of its exploration, development and production activities. The Sponsor relies on digital technology, including information systems and related infrastructure, as well as cloud applications and services, to, among other things, estimate quantities of oil and natural gas reserves, analyze seismic and drilling information, process and record financial and operating data and communicate with employees and third parties. As dependence on digital technologies has increased, cyber incidents, including deliberate attacks and attempts to gain unauthorized access to computer systems and networks, have increased in frequency and sophistication. These threats pose a risk to the security of the Sponsor's systems and networks, the confidentiality, availability and integrity of its data and the physical security of its employees and assets. Any cyber-attack could have a material adverse effect on the Sponsor's reputation, competitive position, business, financial condition and results of operations, and could have a material adverse effect on the Trust. Cyber-attacks or security breaches also could result in litigation or regulatory action, as well as significant additional expense to the Sponsor to implement further data protection measures.

In addition to the risks presented to the Sponsor's systems and networks, cyber-attacks affecting oil and natural gas distribution systems maintained by third parties, or the networks and infrastructure on which they rely, could delay or prevent delivery to markets. A cyber-attack of this nature would be outside the Sponsor's ability to control, but could have a material adverse effect on the Sponsor's business, financial condition and results of operations, and could have a material adverse effect on the Trust.

Cyber-attacks or other failures in telecommunications or IT systems could result in information theft, data corruption and significant disruption of the Trustee's operations.

The Trustee depends heavily upon IT systems and networks in connection with its business activities. Despite a variety of security measures implemented by the Trustee, events such as the loss or theft of back-up tapes or other data storage media could occur, and the Trustee's computer systems could be subject to physical and electronic break-ins, cyber-attacks and similar disruptions from unauthorized tampering, including threats that may come from external factors, such as governments, organized crime, hackers and third parties to whom certain functions are outsourced, or may originate internally from within the respective companies.

If a cyber-attack were to occur, it could potentially jeopardize the confidential, proprietary and other information processed and stored in, and transmitted through, the Trustee's computer systems and networks, or otherwise cause interruptions or malfunctions in the operations of the Trust, which could result in litigation, increased costs and regulatory penalties. It is possible that a cyber incident will not be discovered for some time after it occurs, which could increase exposure to these consequences.

TAX RISKS RELATED TO THE TRUST UNITS

The Trust has not requested a ruling from the IRS regarding the tax treatment of the Trust. If the IRS were to determine (and be sustained in that determination) that the Trust is not a "grantor trust" for U.S. federal income tax purposes, the Trust could be subject to more complex and costly tax reporting requirements that could reduce the amount of cash available for distribution to Trust unitholders.

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

If the Trust were treated for U.S. federal income tax purposes as a partnership, it likely would be subject to new audit procedures that for taxable years beginning after December 31, 2017, alter the procedures for auditing large partnerships and also alter the procedures for assessing and collecting income taxes due (including applicable penalties and interest) as a result of an audit. These rules effectively would impose an entity level tax on the Trust, and unitholders may have to bear the expense of the adjustment even if they were not Trust unitholders during the audited taxable year.

Neither the Sponsor nor the Trustee has requested a ruling from the IRS regarding the tax status of the Trust, and neither the Sponsor nor the Trust can provide any assurance that such a ruling would be granted if requested or that the IRS will not challenge these positions on audit.

Trust unitholders should be aware of the possible state tax implications of owning Trust Units.

Trust unitholders are required to pay taxes on their share of the Trust's income even if they do not receive any cash distributions from the Trust.

Trust unitholders are treated as if they own the Trust's assets and receive the Trust's income and are directly taxable thereon as if no Trust were in existence. Because the Trust generates taxable income that could be different in amount than the cash the Trust distributes, Trust unitholders are required to pay any U.S. federal income taxes and, in some cases, state and local income taxes on their share of the Trust's taxable income even if they receive no cash distributions from the Trust. A Trust unitholder may not receive cash distributions from the Trust equal to such unitholder's share of the Trust's taxable income or even equal to the actual tax liability that results from that income.

A portion of any tax gain on the disposition of the Trust Units could be taxed as ordinary income.

If a Trust unitholder sells Trust Units, he or she will recognize a gain or loss equal to the difference between the amount realized and his or her tax basis in those Trust Units. A substantial portion of any gain recognized may be taxed as ordinary income due to potential recapture items, including depletion recapture.

The Trust allocates its items of income, gain, loss and deduction between transferors and transferees of the Trust 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 Trust Unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among the Trust unitholders.

The Trust generally allocates its items of income, gain, loss and deduction between transferors and transferees of the Trust 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 Trust 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 Trust unitholders affected by the issue and result in an increase in the administrative expense of the Trust in subsequent periods.

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

Item 1B. *Unresolved Staff Comments.*

None.

Item 1C. *Cybersecurity.*

The Trust has no directors or executive officers. The affairs of the Trust are managed by the Trustee. The Trust falls under the cybersecurity program of The Bank of New York Mellon Corporation (“BNY Mellon”), the parent corporation of The Bank of New York Mellon Trust Company, N.A. As further described in its 2024 Annual Report, BNY Mellon maintains a broad range of defenses aimed at remaining abreast of and responding to evolving cybersecurity threats impacting it, its operations, its clients, its third-party service providers and the broader financial services sector.

Risk Management Strategy and Procedures

BNY Mellon has implemented policies and procedures designed to detect, prevent and respond to malicious and accidental disruptions to the delivery of critical technology services. BNY Mellon’s cybersecurity risk management program is embedded in its three lines of defense model.

As part of its first line of defense, BNY Mellon maintains a dedicated Information Security Division (“ISD”), led by the Chief Information Security Officer (the “CISO”), that is responsible for the day-to-day management of risks from cybersecurity threats. ISD’s responsibilities include cybersecurity threat intelligence, incident response and other cybersecurity operations aimed at enabling BNY Mellon to identify, assess and manage existing and emerging cybersecurity threats. ISD monitors for potential threats and communicates relevant risks to the CISO and other members of executive management. Additionally, ISD maintains a cybersecurity incident response and reporting process pursuant to which cybersecurity incidents are classified according to their severity based upon an assessment of multiple factors. Certain cybersecurity incidents may activate enterprise-wide resiliency processes, which include, among other things, escalation through the management and Board committee structures described below. In addition, BNY Mellon maintains a preparedness program designed to reinforce cybersecurity risk management practices and compliance with BNY Mellon’s policies and procedures. The preparedness program includes mandatory training for all employees, contractors and consultants, enhanced training for those in roles presenting higher risk, calibrated phishing email simulations, distribution of information security awareness materials and cybersecurity event simulation exercises. In addition, BNY Mellon leverages both internal and external assessments and engages with third-party assessors, consultants and auditors to evaluate and test its cybersecurity controls and provide guidance on potential improvements, including design and operating effectiveness. BNY Mellon has standing arrangements with third parties to assist BNY Mellon in identifying, assessing and managing cybersecurity threats, including in connection with risk assessments, penetration testing, legal advice and other aspects of BNY Mellon’s cybersecurity risk management and incident response processes.

BNY Mellon has a defined third-party governance framework to help manage the risk posed to it by the use of third-party service providers. BNY Mellon evaluates the risk posed by third-party service engagements based on multiple factors. BNY Mellon has protocols that seek to mitigate cybersecurity risks associated with third-party service providers based on the risk level assigned to such third party, which may include mandatory contractual obligations or the implementation of additional controls by BNY Mellon and/or the applicable service provider.

ISD is subject to ongoing review and challenge from Technology Risk Management, which is a part of the independent second line of defense risk function. Technology Risk Management, together with the broader Risk & Compliance group, is responsible for and manages BNY Mellon's risk management framework and establishes guidance for ISD and management designed to help identify, assess and manage cybersecurity risk.

BNY Mellon's Internal Audit function serves as the third line of defense and provides an independent view on how effectively the organization as a whole manages cybersecurity risk.

Risk Management Oversight and Governance

BNY Mellon's management is responsible for assessing and managing BNY Mellon's material risks from cybersecurity threats with oversight provided by its Board of Directors (the "Board") and the Board committees. The Risk Committee of the Board has primary responsibility for oversight of the overall operation of BNY Mellon's risk management framework, including policies and practices addressing cybersecurity risk, and is responsible for the oversight of the second line of defense with respect to its cybersecurity risk management responsibilities. The Technology Committee of the Board and the full Board regularly receive reports and briefings from management concerning cybersecurity matters, including any significant changes to BNY Mellon's cybersecurity program. BNY Mellon also has protocols for escalating cybersecurity threats and incidents to the Technology Committee of the Board and the full Board. In addition, the Audit Committee of the Board monitors and oversees the performance of Internal Audit, including with respect to its cybersecurity risk management responsibilities.

At the management level, BNY Mellon's Technology Oversight Committee, which is the senior management committee responsible for the governance and oversight of BNY Mellon's significant technology projects and initiatives, reviews reports from management concerning ISD and is responsible for, among other things, escalating issues, including significant cybersecurity threats and incidents, to the Technology Committee of the Board. The Technology Oversight Committee is chaired by the Chief Information Officer (the "CIO") and its members include the CISO.

BNY Mellon's Technology Risk Committee is the most senior governance committee primarily focused on cybersecurity and technology risk issues and is a part of the second line of defense risk function. It is responsible for, among other things, overseeing and reviewing emerging cybersecurity risks, significant cybersecurity incidents and remediation plans. The Technology Risk Committee receives reports from management and has protocols for escalating certain issues and risks to the Senior Risk and Control Committee and the Risk Committee of the Board. The Technology Risk Committee is chaired by the interim Chief Technology Risk Officer. Members include key leaders from the first line of defense, including the CISO.

BNY Mellon's CIO, CISO and interim Chief Technology Risk Officer each have extensive experience in assessing and managing risks from cybersecurity threats. BNY Mellon's CISO joined BNY Mellon in 2022 and previously served as head of information security at a Fortune 500 biopharmaceutical company and an information technology company, as well as the Global Chief Technology Officer at a large cybersecurity company. BNY Mellon's CIO joined BNY Mellon in September 2024 from a large multinational company, where she was responsible for overseeing information technology and cybersecurity operations. BNY Mellon's interim Chief Technology Risk Officer joined BNY Mellon in November 2024 and has previous experience as Global Head of Cyber, Technology and Information Security Risk Management at a global systemically important financial institution and over a decade of experience serving the U.S. intelligence community in a variety of cybersecurity-related positions.

Item 2. *Properties.*

Description of the Underlying Properties

The Underlying Properties consist of producing and non-producing interests in oil and natural gas units, wells and lands in Texas, Louisiana and New Mexico. The Underlying Properties include a portion of the assets in east Texas and north Louisiana acquired by Enduro from Denbury Resources Inc. in December 2010, and all of the assets in the Permian Basin of New Mexico and west Texas acquired by Enduro from Samson Investment Company and ConocoPhillips Company in January 2011 and February 2011, respectively. In August 2018, the Sponsor purchased the Underlying Properties from Enduro and assumed all of Enduro's obligations under the Trust Agreement and other instruments to which Enduro and the Trustee were parties. The Underlying Properties are divided into two geographic regions: the Permian Basin region and East Texas/North Louisiana region.

As of December 31, 2024, the Underlying Properties had proved reserves of 10.8 MMBoe with 92% and 97% of the volumes and PV-10 value, respectively, attributable to proved developed reserves. All of the 10.8 MMBoe of proved reserves, based on PV-10 value, were operated by third-party operators.

The Sponsor's interests in the Underlying Properties require the Sponsor to bear its proportionate share of the costs of development and operation of such properties. As of December 31, 2024, the Sponsor held average working interests of approximately 19% and 15% and average net revenue interests of approximately 16% and 12% in the Underlying Properties located in the Permian Basin and East Texas/North Louisiana regions, respectively. The Underlying Properties are also burdened by non-cost bearing interests owned by third parties consisting primarily of overriding royalty and royalty interests.

Reserves

Cawley, Gillespie & Associates, Inc. ("Cawley Gillespie"), independent petroleum and geological engineers, estimated crude oil (including natural gas liquids) and natural gas proved reserves of the Underlying Properties' full economic life and for the Trust life as of December 31, 2024. Numerous uncertainties are inherent in estimating reserve volumes and values, and the estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of the reserves may vary significantly from the original estimates. In addition, the reserves and net revenues attributable to the Net Profits Interest include only 80% of the reserves attributable to the Underlying Properties that are expected to be produced within the term of the Net Profits Interest.

The independent petroleum engineer's report as to the proved oil and natural gas reserves as of December 31, 2024 was prepared by Cawley Gillespie. Cawley Gillespie, whose firm registration number is F-693, was founded in 1961 and is a leader in the evaluation of oil and gas properties. The technical person at Cawley Gillespie primarily responsible for overseeing the reserve estimates with respect to the Underlying Properties and the Net Profits Interest attributable to the Trust is W. Todd Brooker. Mr. Brooker has been a petroleum consultant for Cawley Gillespie since 1992 and is currently the Senior Vice President. He is a registered professional engineer in the State of Texas (license no. 83462) and a graduate of the University of Texas with a Bachelor of Science in Petroleum Engineering.

Information concerning changes in net proved reserves attributable to the Trust, and the calculation of the standardized measure of the related discounted future net revenues is contained in the notes to the financial statements of the Trust included in this Form 10-K. COERT has not filed reserve estimates covering the Underlying Properties with any other federal authority or agency.

The following table summarizes the estimated proved reserve quantities and PV-10 attributable to the Trust and Underlying Properties as of December 31, 2024 and 2023:

	Trust Net Profits Interest				Underlying Properties			
	Oil[1] (MBbls)	Natural Gas (MMcf)	Total[2] (MBoe)	PV-10[3] (in thousands)	Oil[1] (MBbls)	Natural Gas (MMcf)	Total[2] (MBoe)	PV-10[3] (in thousands)
2024								
Proved Developed Producing	2,437	5,892	3,419	$ 76,822	5,595	13,374	7,824	$ 96,027
Proved Developed Non-Producing	4	7,290	1,219	8,293	6	12,840	2,146	10,367
Proved Undeveloped	298	962	458	6,246	575	1,846	883	3,096
2023								
Proved Developed Producing	1,826	4,545	2,584	$ 62,512	4,239	10,481	5,986	$ 78,140
Proved Developed Non-Producing	55	3,162	582	6,774	85	4,984	916	8,465
Proved Undeveloped	283	1,648	558	7,370	552	2,924	1,039	4,615

(1) Reserves for natural gas liquids are included as a component of oil reserves.

(2) Boe represents an approximate energy equivalent basis such that one Bbl of crude oil equals approximately six Mcf of natural gas. However, the value of oil and natural gas value and the value of reserve volumes of oil and natural gas are often substantially different than the amount implied by the Boe ratio.

(3) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved crude oil and natural gas reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash inflows using the twelve-month unweighted arithmetic average of the first-day-of-the-month commodity prices, after adjustment for differentials in location and quality, for each of the preceding twelve months. An estimate of PV-10 is provided because it provides useful information to investors as it is widely used by professional analysts and sophisticated investors when evaluating oil and gas companies. PV-10 is considered relevant and useful for evaluating the relative monetary significance of oil and natural gas reserves. PV-10 is not intended to represent the current market value of the estimated reserves of the Underlying Properties. PV-10 differs from standardized measure of discounted future net cash flows because it does not include the effect of future income taxes. Please refer to the notes to the financial statements of the Trust included in this Form 10-K.

Reserve quantities and revenues for the Net Profits Interest were estimated from projections of reserves and revenues attributable to the Underlying Properties. Since the Trust has a defined Net Profits Interest, the Trust does not own a specific percentage of the oil and natural gas reserve quantities. Accordingly, reserves allocated to the Trust pertaining to its 80% Net Profits Interest in the Underlying Properties have effectively been reduced to reflect recovery of the Trust's 80% portion of applicable production and development costs. Because Trust reserve quantities are determined using an allocation formula, any changes in actual or assumed prices or costs will result in revisions to the estimated reserve quantities allocated to the Net Profits Interest.

Estimates of proved reserves were prepared in accordance with guidelines prescribed by the SEC and the Financial Accounting Standards Board, which require that reserve estimates be prepared under existing economic and operating conditions based upon an average of the NYMEX first-day-of-the-month commodity price during the 12-month period ending on the balance sheet date with no provision for price and cost escalations except by contractual arrangements. Prices used in estimating reserves were as follows:

	2024	2023	2022
Oil (per Bbl)	$ 75.48	$ 78.22	$ 93.67
Natural gas (per Mcf)	$ 2.13	$ 2.64	$ 6.36

Changes in Proved Undeveloped Reserves

During the year ended December 31, 2024, proved undeveloped reserves of the Underlying Properties decreased 0.2 MMBoe primarily due to the decrease in the estimated reserves for the booked, non-operated wells in Haynesville shale of Louisiana, partially offset by the increase in the amount of booked, non-operated Wolfcamp shale wells in the Permian Basin. The following is a summary of the changes in quantities of proved undeveloped reserves for the Underlying Properties during the year ended December 31, 2024.

	Underlying Properties		
	Oil[1] (MBbls)	Natural Gas (MMcf)	Total (MBoe)
Balance – December 31, 2023	552	2,924	1,039
Development	6	4	7
Revisions and Other	17	(1,082)	(156)
Balance – December 31, 2024	575	1,846	890

(1) Reserves for natural gas liquids are included as a component of oil reserves.

Producing Acreage and Well Counts

For the following data, "gross" refers to the total number of wells or acres in the Underlying Properties and "net" refers to gross wells or acres multiplied by the percentage working interest owned by the Sponsor and in turn attributable to the Underlying Properties. All of the acreage comprising the Underlying Properties is held by production. Although many wells produce both oil and natural gas, a well is categorized as an oil well or a natural gas well based upon the ratio of oil to natural gas production.

The Underlying Properties are interests in properties located in the Permian Basin of west Texas and New Mexico and in the East Texas/North Louisiana region. The following is a summary of the approximate acreage of the Underlying Properties at December 31, 2024:

	Acres	
	Gross	**Net**
Permian Basin	119,112	33,830
East Texas/North Louisiana	10,424	2,840
Total	129,536	36,670

The following is a summary of the producing wells on the Underlying Properties as of December 31, 2024:

	Oil		Natural Gas	
	Gross Wells(1)	**Net Wells**	**Gross Wells(1)**	**Net Wells**
Permian Basin	2,174	219	66	8
East Texas/North Louisiana	—	—	308	47
Total	2,174	219	374	55

(1) The Sponsor's total producing wells include 2,548 non-operated wells.

The following is a summary of the number of development and exploratory wells drilled on the Underlying Properties located in the Permian Basin and East Texas/North Louisiana during the last three years:

	Year Ended December 31,					
	2024		**2023**		**2022**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Permian Basin						
Development Wells:						
Productive	47	1.2	15	0.5	5	0.1
Dry holes	—	—	—	—	—	—
	—	—	—	—	—	—
Exploratory Wells:						
Productive	—	—	—	—	—	—
Dry holes	—	—	—	—	—	—
	—	—	—	—	—	—
Total:						
Productive	47	1.2	15	0.5	5	0.1
Dry holes	—	—	—	—	—	—
	—	—	—	—	—	—

	Year Ended December 31,					
	2024		2023		2022	
	Gross	Net	Gross	Net	Gross	Net
East Texas/North Louisiana						
Development Wells: (1)						
Productive	6	0.3	—	—	3	0.1
Dry holes	—	—	—	—	—	—
	—	—	—	—	—	—
Exploratory Wells:						
Productive	—	—	—	—	—	—
Dry holes	—	—	—	—	—	—
	—	—	—	—	—	—
Total:						
Productive	6	0.3	—	—	3	0.1
Dry holes	—	—	—	—	—	—
	—	—	—	—	—	—

(1) Production of natural gas liquids is immaterial and included as a component of natural gas production.

Major Producing Areas

Substantially all of the Underlying Properties are located in mature oil fields that are characterized by long production histories. Based on the reserve reports, approximately 56% of the future production from the Underlying Properties is expected to be oil and approximately 44% is expected to be natural gas.

Permian Basin Region

The Permian Basin is one of the largest and most prolific oil and natural gas producing basins in the United States. The Underlying Properties in the Permian Basin contain 119,112 gross (33,830 net) acres in Texas and New Mexico.

The largest fields in the Underlying Properties are located primarily in the Permian Basin (measured by Boe reserves at December 31, 2024). The largest field in the Permian Basin region is the Spraberry field, which individually accounts for 21 percent of the Underlying Properties reserves as of December 31, 2024. This unit produces from the Wolfcamp formations at depths up to 8,500 feet. Proved reserves attributable to the Underlying Properties in the Eunice Monument field were 2.2 MMBoe as of December 31, 2024. This field is operated by Pioneer Natural Resources, Ovintiv and Franklin Mountain.

East Texas/North Louisiana Region

The Underlying Properties contain interests in 10,424 gross (2,840 net) acres in the East Texas/North Louisiana region across three fields: the Elm Grove field, operated primarily by BP Energy, Aethon Energy Operating, LLC and Comstock Oil & Gas, LLC; and the Kingston field, operated by EXCO Resources and Diversified Production, LLC. All proved reserves attributable to the Underlying Properties in the East Texas/North Louisiana region are located in the Haynesville, Cotton Valley, and Hosston reservoirs of the Elm Grove and Kingston fields. Proved reserves attributable to the Underlying Properties in the Elm Grove and Kingston fields were 2.3 MMBoe and 0.1 MMBoe, respectively, as of December 31, 2024.

Production and Reserves

The following table shows the net production, average sales price, average lease operating expense, and proved reserves as of year-end for the Underlying Properties located in the Permian Basin of west Texas and New Mexico and in the East Texas/North Louisiana region, which relates to the amounts included in the net profits calculation for the distributions paid during the years ended December 31, 2024, 2023 and 2022.

		Year Ended December 31,		
		2024	2023	2022
Permian Basin	Oil Sales Volumes (Bbls)	634,618	439,122	495,434
	Natural Gas[(1)] Sales Volumes (Mcf)	3,324,021	1,700,680	1,980,171
	Total Sales Volumes (Boe)	1,188,621	722,568	825,462
	Oil Average Sales Price per Bbl	$ 79.20	$ 78.85	$ 90.02
	Natural Gas Average Sales Price per Mcf	$ 1.98	$ 3.52	$ 5.12
	Average Lease Operating Expense per Boe	$ 18.46	$ 30.44	$ 25.42
	Proved Reserves (MBoe)	8,510	6,830	10,881
East Texas/North Louisiana	Oil Sales Volumes (Bbls)	384	418	1,132
	Natural Gas[(1)] Sales Volumes (Mcf)	2,255,872	1,081,888	1,377,062
	Total Sales Volumes (Boe)	376,363	180,733	230,643
	Oil Average Sales Price per Bbl	$ 69.91	$ 71.23	$ 61.47
	Natural Gas Average Sales Price per Mcf	$ 2.11	$ 4.22	$ 5.33
	Average Lease Operating Expense per Boe	$ 4.05	$ 8.61	$ 8.18
	Proved Reserves (MBoe)	2,343	1,112	827
Total	Oil Sales Volumes (Bbls)	635,002	439,540	496,566
	Natural Gas[(1)] Sales Volumes (Mcf)	5,579,893	2,782,568	3,357,233
	Total Sales Volumes (Boe)	1,564,984	903,302	1,056,105
	Oil Average Sales Price per Bbl	$ 79.20	$ 78.84	$ 89.96
	Natural Gas Average Sales Price per Mcf	$ 2.03	$ 3.79	$ 5.21
	Average Lease Operating Expense per Boe	$ 15.00	$ 26.07	$ 21.66
	Proved Reserves (MBoe)	10,853	7,941	11,708

(1) Production of natural gas liquids is immaterial and included as a component of natural gas production.

Abandonment and Sale of Underlying Properties

Each of the operators of the Underlying Properties or any transferee has the right to abandon its interest in any well or property if it reasonably believes a well or property ceases to produce or is not capable of producing in commercially paying quantities. Upon termination of the lease, the portion of the Net Profits Interest relating to the abandoned property will be extinguished.

The Sponsor generally may sell all or a portion of its interests in the Underlying Properties, subject to and burdened by the Net Profits Interest, without the consent of the Trust unitholders. Following the sale of all or any portion of the Underlying Properties, the purchaser will be bound by the obligations of the Sponsor under the Trust Agreement and the Conveyance with respect to the portion sold. In addition, the Sponsor may, without the consent of the Trust unitholders, require the Trustee to release the Net Profits Interest associated with any lease that accounts for no more than 0.25% of the total production from the Underlying Properties in the prior 12 months, provided that the Net Profits Interest covered by such releases cannot exceed, during any 12-month period, an aggregate fair market value to the Trust of $500,000. These releases may be made only in connection with a sale by the Sponsor to a non-affiliate of the relevant Underlying Properties and are conditioned upon the Trust receiving an amount equal to the fair value to the Trust of such Net Profits Interest. In May 2023, the Sponsor sold approximately $0.3 million in non-producing, non-cash flowing acreage to a private oil company, free and clear of the Net Profits Interest, as permitted under the Trust Agreement. The proceeds from this sale attributable to the Trust's Net Profits Interest were included in the distribution that was paid to Trust unitholders on August 14, 2023.

Title to Properties

The properties comprising the Underlying Properties are or may be subject to one or more of the burdens and obligations described below. To the extent that these burdens and obligations affect the Sponsor's rights to production or the value of production from the Underlying Properties, they have been taken into account in calculating the Trust's interests and in estimating the size and the value of the reserves attributable to the Underlying Properties.

The Sponsor's interests in the oil and natural gas properties comprising the Underlying Properties are typically subject to one or more of the following:

- royalties and other burdens, express and implied, under oil and natural gas leases and other arrangements;
- overriding royalties, production payments and similar interests and other burdens created by the Sponsor's predecessors in title;
- a variety of contractual obligations arising under operating agreements, farm-out agreements, production sales contracts and other agreements that may affect the Underlying Properties or their title;

- liens that arise in the normal course of operations, such as those for unpaid taxes, statutory liens securing unpaid suppliers and contractors and contractual liens under operating agreements that are not yet delinquent or, if delinquent, are being contested in good faith by appropriate proceedings;

- pooling, unitization and communitization agreements, declarations and orders;

- easements, restrictions, rights-of-way and other matters that commonly affect property;

- conventional rights of reassignment that obligate the Sponsor to reassign all or part of a property to a third party if the Sponsor intends to release or abandon such property;

- preferential rights to purchase or similar agreements and required third party consents to assignments or similar agreements;

- obligations or duties affecting the Underlying Properties to any municipality or public authority with respect to any franchise, grant, license or permit, and all applicable laws, rules, regulations and orders of any governmental authority; and

- rights reserved to or vested in the appropriate governmental agency or authority to control or regulate the Underlying Properties and also the interests held therein, including the Sponsor's interests and the Net Profits Interest.

The Sponsor has informed the Trustee that the Sponsor believes the burdens and obligations affecting the properties comprising the Underlying Properties are conventional in the industry for similar properties. The Sponsor has also informed the Trustee that the Sponsor believes the existing burdens and obligations do not, in the aggregate, materially interfere with the use of the Underlying Properties and will not materially adversely affect the Net Profits Interest or its value.

To give third parties notice of the Net Profits Interest, Enduro recorded the Conveyance in Texas, Louisiana and New Mexico in the real property records in each Texas, Louisiana or New Mexico county in which the Underlying Properties are located, or in such other public records of those states as required under applicable law to place third parties on notice of the Conveyance.

In a bankruptcy of the Sponsor, to the extent Louisiana or New Mexico law were held to be applicable, the Net Profits Interest might be considered an asset of the bankruptcy estate and used to satisfy obligations to creditors of the Sponsor, in which case the Trust would be an unsecured creditor of the Sponsor at risk of losing the entire value of the Net Profits Interest to senior creditors. See "Risk Factors—Financial Risks—In the event of the bankruptcy of the Sponsor, if a court were to hold that the Net Profits Interest was part of the bankruptcy estate, the Trust may be treated as an unsecured creditor with respect to the Net Profits Interest attributable to properties in Louisiana and New Mexico" in Part I, Item 1A of this Form 10-K.

The Sponsor believes that its title to the Underlying Properties and the Trust's title to the Net Profits Interest are each good and defensible in accordance with standards generally accepted in the oil and gas industry, subject to such exceptions as are not so material to detract substantially from the use or value of such Underlying Properties or Net Profits Interest. Under the terms of the Conveyance creating the Net Profits Interest, the Sponsor has provided a special warranty of title with respect to the Net Profits Interest, subject to the burdens and obligations described in this section. Please see "Risk Factors—Financial Risks—The Trust Units may lose value as a result of title deficiencies with respect to the Underlying Properties" in Part I, Item 1A of this Form 10-K.

Item 3. ***Legal Proceedings.***

Currently, there are not any legal proceedings pending to which the Trust is a party or of which any of its property is the subject. The foregoing does not address any legal proceedings to which the Sponsor or any of the third-party operators may be a party or subject or that may otherwise relate to or affect any of the Underlying Properties or the operations of any of the operators of the Underlying Properties.

Item 4. ***Mine Safety Disclosures.***

Not applicable

PART II

Item 5. ***Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities.***

The Trust Units trade on the New York Stock Exchange under the symbol "PVL." At December 31, 2024, there were 33,000,000 Trust Units outstanding. On March 19, 2025, there were five unitholders of record. This number does not include owners for whom Trust Units may be held in "street" name.

Distributions

Each month, the Trustee determines the amount of funds available for distribution to the Trust unitholders. Available funds are the excess cash, if any, received by the Trust from the Net Profits Interest and other sources (such as interest earned on any amounts reserved by the Trustee) that month, over the Trust's incurred expenses for that month. Available funds are reduced by any cash the Trustee decides to hold as a reserve against future liabilities. The holders of Trust Units as of the applicable record date (generally the last business day of each calendar month) are entitled to monthly distributions payable on or before the tenth business day after the record date (or the next succeeding business day). For further information on distributions to Trust unitholders, see Note 5 of the Notes to Financial Statements in Part II, Item 8 of this Form 10-K.

Equity Compensation Plans

The Trust does not have any employees and does not maintain any equity compensation plans.

Recent Sales of Unregistered Securities

There were no equity securities sold by the Trust during the year ended December 31, 2024.

Purchases of Equity Securities

There were no purchases of Trust Units by the Trust or any affiliated purchaser during the fourth quarter of 2024.

Item 6. ***[Reserved]***

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

This discussion contains forward-looking statements. Please refer to "Forward-Looking Statements" for an explanation of these types of statements.

Overview

Permianville Royalty Trust, previously known as Enduro Royalty Trust, a statutory trust created in May 2011, completed its initial public offering in November 2011. The Trust's only asset and source of income is the Net Profits Interest, which entitles the Trust to receive 80% of the net profits from oil and natural gas production from the Underlying Properties. The Net Profits Interest is passive in nature and neither the Trust nor the Trustee has any management control over or responsibility for costs relating to the operation of the Underlying Properties. Additionally, third parties operate substantially all of the wells on the Underlying Properties and, therefore, the Sponsor is not in a position to control the timing of development efforts, associated costs, or the rate of production of the reserves.

The Trust is required to make monthly cash distributions of substantially all of its monthly cash receipts, after deducting the Trust's administrative expenses, to holders of record (generally the last business day of each calendar month) on or before the tenth business day after the record date. The Net Profits Interest is entitled to a share of the profits from and after July 1, 2011 attributable to production occurring on or after June 1, 2011. The amount of Trust revenues and cash distributions to Trust unitholders depends on, among other things:

- oil and natural gas sales prices;
- volumes of oil and natural gas produced and sold attributable to the Underlying Properties;
- production and development costs;
- price differentials;
- potential reductions or suspensions of production;
- the amount and timing of Trust administrative expenses; and
- the establishment, increase, or decrease of reserves for approved development expenses or future liabilities of the Trust.

Generally, the Sponsor receives cash payment for oil production 30 to 60 days after it is produced and for natural gas production 60 to 90 days after it is produced.

2024 Recap and 2025 Outlook

The average NYMEX oil and natural gas prices experienced continued volatility in 2024, with average oil prices relatively unchanged year-over-year but seeing lower highs than the prior year. The average NYMEX oil price declined from $77.61 per Bbl in calendar year 2023 to $75.79 per Bbl in calendar year 2024, a decline of 2%. Meanwhile, the price range varied from high of $86.91 per Bbl in April 2024 to a low of $65.75 per Bbl in September 2024. The second half of 2024 saw more muted prices as the U.S. general election approached and macroeconomic concerns remained. Natural gas prices faced continued volatility as well, but ended the year higher compared to crude oil's lower trajectory over the same period. The average NYMEX natural gas price declined from $2.66 per MMBtu in calendar year 2023 to $2.41 per MMBtu in calendar year 2024, a decline of 10%. Prices for natural gas saw some of the lowest levels ever on an inflation-adjusted basis in 2024, ranging from a low of $1.56 per MMBtu in March 2024 to a high of $3.95 per MMBtu in late December 2024, near the high for the year and among the highest levels since December 2022. Although average commodity prices declined for the year amid continued volatility, recorded third-party operator drilling activity on the Underlying Properties increased materially, which contributed to a 202% increase in development expenses for the production months of 2024 compared to 2023. The increase in activity despite lower average prices s due in part to the nature of the operators of the Underlying Properties, with a substantial majority of the capital expenditures being directed by large, public operators, most of which are investment grade rated with longer-term capital planning cycles.

COERT believes that the outlook for the oil and gas industry remains mixed, with oil prices having ended 2024 at the low end of the $65-90 per Bbl range experienced since August 2022 and with geopolitical and tariff concerns weighing further on the outlook for global demand. However, the price of natural gas, which is more regional given historical export constraints, rallied at the end of 2024 given a colder winter compared to recent years and an expected expanding U.S. LNG export capacity in the coming years. In addition, mergers and acquisitions have continued to change the makeup of the companies deploying capital in the sector over the last several years. As larger public companies continue to acquire smaller public companies and private operators, COERT believes that these larger companies are likely to react differently to commodity price volatility than smaller operators have in historical cycles, as evidenced by the material increase in capital expenditures on the Underlying Properties in 2024 despite lower year-over-year average prices. Nevertheless, the capital spending activity or operating performance for the Underlying Properties under new third-party operatorship in the future may not be consistent with such activity or performance experienced under previous third-party operators in prior years. Although the estimated 2025 capital spending budgets for operators of the Underlying Properties are still to be determined, COERT has advised the Trustee that early indications suggest 2025 will see lower total spending than the elevated levels of 2024.

Given forward commodity prices, changing ownership between some of the operators of the Underlying Properties as well as an uncertain macroeconomic outlook, planned capital expenditures during 2025 remain somewhat uncertain. Based on currently available information, COERT anticipates 2025 capital expenditures on the Underlying Properties to range from $7.0 million to $13.0 million, or $5.6 million to $10.4 million net to the Trust's 80% Net Profits Interest. This would represent a decrease from 2024 levels, partly due to lower projected oil prices, somewhat offset by possibly sustained activity levels in the Haynesville area of the Underlying Properties given higher relative natural gas prices. COERT indicates that it continues to have access to adequate capital and liquidity to fund such capital expenditures as they come due.

In addition to continued capital expenditure participation, COERT believes there could be further opportunity in 2025 for prospective divestitures of some or all of the Underlying Properties, as operators of some of the Underlying Properties look to consolidate non-operated interests and acreage given recent merger and acquisition activity in the industry.

Capex Drilling Activity Update

Presented below is a summary of the current status of certain notable capital projects recently undertaken on the Underlying Properties pursuant to the capital expenditure program described above.

The following table is not intended to be a comprehensive list reflecting all capital expenditures to date. In addition, there can often be a several-month delay from the time of capital expenditures to the time of production and cash flows attributable to the Underlying Properties, especially given the non-operated nature of the Underlying Properties.

Operator	**Region**	**Number of Wells**	**Underlying Properties W/I**	**Project**	**Capex Cumulative Total (in thousands)**	**Status**
Large Cap E&P 1	Conventional Permian	N/A (Field)	0.8%	New Drills / Workovers	$ 446	In-process/ Continual Program
Large Private E&P 1	Haynesville	6	3.5%	D&C New Drills	$ 2,415	6 Producing Awaiting Revenues
PE-Backed Private 1	Delaware	4	0.7%	D&C New Drills	-	4 Drilling In-Process
Large Cap E&P 2	Midland	4	3.4%	D&C New Drills	$ 683	4 Drilling In-Process
Large Cap E&P 3	Delaware	19	1.0%	D&C New Drills	-	19 Pre Drills
Large Major Cap E&P 1	Haynesville	3	13.6%	D&C New Drills	$ 3,032	3 Drilling In-Process

The Sponsor expects that a majority of the projects above that are still in process or awaiting first revenues will be completed and will begin producing during 2025.

Sale of 2023 Divestiture Properties

On May 3, 2023, the Sponsor notified the Trustee that the Sponsor had entered into an agreement to divest certain acreage and associated production in the Permian Basin (the "2023 Divestiture Properties") that constituted part of the Underlying Properties and were therefore burdened by the Trust's Net Profits Interest, for a total purchase price of approximately $6.7 million. On July 19, 2023, at a special meeting of Trust unitholders, the unitholders approved the foregoing transaction and the release of the Trust's Net Profits Interest in the 2023 Divestiture Properties. On August 9, 2023, the Sponsor completed the sale of the 2023 Divestiture Properties, and the Trustee, on behalf of the Trust, reconveyed, terminated and released to the Sponsor the Net Profits Interest with respect to the 2023 Divestiture Properties. The total proceeds received by the Sponsor from the sale of the 2023 Divestiture Properties, after preliminary closing adjustments, were approximately $6.5 million, inclusive of the escrow funded by the buyer and partial expense reimbursement associated with the proxy solicitation. The Sponsor deducted the final transaction expenses from the sales proceeds, along with an escrow amount of $250,000 to cover possible indemnification obligations under the purchase and sale agreement (the "Indemnification Escrow Amount"), to arrive at final net proceeds, based upon the Trust's Net Profits Interest.

On September 20, 2023, the Trust announced a special cash distribution to Trust unitholders of $0.069670 per Trust Unit, payable on October 13, 2023 to Trust unitholders of record on October 2, 2023, reflecting 50% of the Trust's share of the net proceeds, after accounting for the Indemnification Escrow Amount. The remaining 50% of the Trust's share of the net proceeds was temporarily retained by the Sponsor as a source of payment of the Trust's proportionate share of any post-closing purchase price adjustments, with any amount remaining (less any amounts in dispute) after such adjustments to be paid to the Trust within five business days after finalization of the settlement statement and included in a distribution to Trust unitholders. On November 6, 2023, the Trust announced a special cash distribution to Trust unitholders of $0.077250 per Trust Unit, payable on November 22, 2023 to Trust unitholders of record on November 16, 2023, reflecting the remaining 50% of the Trust's share of the net proceeds (net of the Indemnification Escrow Amount). On March 17, 2025, the Trust announced a special cash distribution to Trust unitholders of $0.008548 per Trust Unit, payable on April 14, 2025 to Trust unitholders of record on March 31, 2025, reflecting the release of the Indemnification Escrow Amount, together with interest, for a total of $282,072.

Results of Operations

The following table displays oil and natural gas sales volumes and average prices from the Underlying Properties, representing the amounts included in the net profits calculation for the distributions paid during the years ended December 31, 2024 and 2023.

	Underlying Properties Sales Volumes		Average Price	
Month of Distribution	**Oil (Bbls)**	**Natural Gas (Mcf)**	**Oil (per Bbl)**	**Natural Gas (per Mcf)**
2024:				
February	115,343	711,124	$ 83.99	$ 2.38
August	346,439	2,610,841	$ 77.10	$ 2.18
September	41,469	394,278	$ 79.53	$ 1.39
October	38,579	374,304	$ 77.69	$ 1.69
November	52,287	1,105,204	$ 79.43	$ 2.44
December	40,886	384,143	$ 75.88	$ 1.78
Total—2024(1)	**635,003**	**5,579,894**	**$ 78.94**	**$ 1.98**
2023:				
January	37,419	250,486	$ 94.66	$ 7.20
February	36,796	222,785	$ 85.39	$ 6.89
March	38,056	217,262	$ 80.01	$ 5.19
April	34,720	204,419	$ 78.48	$ 4.23
May	38,896	191,223	$ 75.01	$ 4.71
June	39,651	241,119	$ 75.60	$ 3.84
July	38,120	195,616	$ 71.94	$ 2.85
August	64,721	604,148	$ 86.52	$ 2.75
September	43,894	204,848	$ 71.99	$ 1.32
October	33,806	227,756	$ 69.15	$ 2.01
November	33,461	222,906	$ 73.07	$ 2.02
Total—2023(2)	**439,540**	**2,782,568**	**$ 78.84**	**$ 3.79**

(1) The table for the year ended December 31, 2024 does not separately display sales volumes for January, March, April and July because the Trust did not pay a distribution with respect to those months, as the net profits interest calculation for each such period was negative.

(2) The year ended December 31, 2023 does not include sales volumes for December as the Trust did not make a distribution in that month, as the Net Profits Interest calculation for the corresponding production period was negative.

Computation of Income from Net Profits Interest Received by the Trust

In connection with the closing of the initial public offering in November 2011, Enduro contributed the Net Profits Interest to the Trust in exchange for 33,000,000 newly issued Trust Units. The Net Profits Interest entitles the Trust to receive 80% of the net profits from the sale and production of oil and natural gas attributable to the Underlying Properties that are produced during the term of the Conveyance, which commenced on July 1, 2011. The Trust's Income from Net Profits Interest consists of monthly net profits attributable to the Net Profits Interest. Net profits income for the years ended December 31, 2024 and 2023 were determined as shown in the following table:

	Year Ended December 31,	
	2024	**2023**
Gross profits:		
Oil sales	$ 50,291,248	$ 34,653,097
Natural gas sales	11,341,855	10,555,426
Total	61,633,103	45,208,523
Costs:		
Direct operating expenses:		
Lease operating expenses	26,801,000	22,136,000
Compression, gathering and transportation	3,773,000	1,696,000
Production, ad valorem and other taxes	4,140,000	2,963,000
Development expenses	20,345,000	6,729,000
Total	55,059,000	33,524,000
Gross proceeds from sale/lease of undeveloped acreage	146,400	306,250
Net profits attributable to Underlying Properties	$ 6,720,503	$ 11,990,773
Percentage allocable to Net Profits Interest	80%	80%
Income from Net Profits Interest	$ 5,376,403	$ 9,592,619
Capex Reserve – Release (Holdback) for anticipated 2023-2024 capital expenditures	(1,000,000)	1,000,000
Less: COERT Loan Repayment	(527,076)	—
Less: Trust general and administrative expenses and cash withheld for expenses	(1,027,825)	(1,327,790)
Distributable income generated by properties prior to divestiture	$ 2,821,500	$ 9,264,829
Income from sale of Net Profits Interest	—	4,848,281
Distributable income	$ 2,821,500	$ 14,113,110

As reflected in the Net Profits Interest calculation for November 2023, direct operating and development expenses exceeded revenues, thereby causing net profits attributable to the Underlying Properties to be negative and resulting in a Net Profits Interest shortfall of approximately $1.2 million. As a result, there was no distribution to Trust unitholders in the month of December 2023. The shortfall of $1.2 million was carried forward to be deducted from future net profits to be generated by the Underlying Properties, and the corresponding revenues and associated direct operating and development expenses are excluded from the calculation of distributable income for the year ended December 31, 2023 detailed in the table above as well as the related sales volumes detailed below. As a result, only eleven months of results are included in the results for the year ended December 31, 2023.

In 2024, net profits from the Underlying Properties were positive, which eliminated the cumulative Net Profits Interest shortfall of $1.2 million and the cumulative outstanding Sponsor advances to the Trust of $0.5 million. Since the Net Profits Interest shortfall was eliminated in 2024, revenues and the associated direct operating and development expenses for the last month of 2023 are included in the calculation of distributable income detailed in the table above for the year ended December 31, 2024 and the related sales volumes are reflected in the table below.

The following table displays oil and natural gas sales volumes and average prices from the Underlying Properties, representing the amounts included in the net profits calculation for distributions paid during the years ended December 31, 2024 and 2023:

	Year Ended December 31,	
	2024	**2023**
Underlying Properties Sales Volumes:		
Oil (Bbls)	635,003	439,540
Natural Gas (Mcf)	5,579,894	2,782,568
Combined (Boe)	1,564,985	903,301
Average Prices:		
Oil – NYMEX (applicable NPI period) ($/Bbl)	$ 78.04	$ 76.83
Differential	$ 1.16	$ 2.01
Oil prices realized ($/Bbl)	$ 79.20	$ 78.84
Natural gas – NYMEX (applicable NPI period) ($/Mcf)	$ 2.28	$ 2.26
Differential	$ (0.25)	$ 1.53
Natural gas prices realized ($/Mcf)	$ 2.03	$ 3.79

Years Ended December 31, 2024 and 2023

Net profits attributable to the Underlying Properties for the year ended December 31, 2024 are calculated from the following:

- oil sales related to oil produced from the Underlying Properties primarily from August 2023 through August 2024;
- natural gas sales related to natural gas produced from the Underlying Properties primarily from July 2023 through July 2024; and
- direct operating and development expenses related to expenses and capital incurred primarily from September 2023 to September 2024.

Net profits attributable to the Underlying Properties for the year ended December 31, 2024 were $6.7 million compared to $12.0 million for the year ended December 31, 2023. As discussed in "—Computation of Income from Net Profits Interest Received by the Trust" above, no distribution was made to Trust unitholders in December 2023 due to the Net Profits Interest shortfall. Accordingly, under the modified cash basis of accounting, the oil and natural gas sales, direct operating expenses and development expenses attributable to the corresponding production period were excluded from the calculation of distributable income for the year ended December 31, 2023 and instead were included in the Trust's results for the year ended December 31, 2024, once the shortfall was recouped. Therefore, several variances between the periods are due to the inclusion of thirteen months of results in the year ended December 31, 2024 compared to eleven months in the year ended December 31, 2023. The $5.3 million decrease in net profits attributable to the Underlying Properties from the 2023 period to the 2024 period was primarily due to the following items:

- Oil sales increased $15.6 million, primarily due to an increase in produced volumes, which increased revenues by $15.4 million. This increase was primarily due to the several new Permian wells that either turned to sales or completed title work and thereby allowed production attributable to prior periods to be released by the operators of the Underlying Properties. Realized oil sales prices increased by less than 1% in the 2024 period compared to the 2023 period, which increased revenues by $0.2 million.

- Natural gas sales increased $0.8 million due to higher produced sales volumes, which increased natural gas sales by $10.6 million. The 46% decrease in realized prices resulted in a $9.6 million decrease in natural gas sales for the year ended December 31, 2024 compared to 2023.

- Lease operating expenses during the year ended December 31, 2024 were $26.8 million compared to $22.1 million during the year ended December 31, 2023, an increase of $4.7 million. Approximately $1.4 million of the 2023 expenses and approximately $1.4 million of the 2024 expenses were attributable to a settlement between COERT and one of the operators of the Underlying Properties relating to a dispute with respect to certain lease operating expenses from 2018 and 2019 that the operator had mistakenly coded for Enduro instead of COERT. In May 2023, COERT and the operator agreed to settle the dispute at a discounted amount, resulting in an incremental lease operating expense adjustment of approximately $0.4 million per month from June 2023 through December 2023, after which no additional amounts relating to the disputed expenses will be owed to the operator. The remaining increase in lease operating expenses in 2024 was primarily due to several new drilled wells that came online during the year.

- Compression, gathering and transportation expenses increased from $1.7 million in 2023 to $3.8 million in 2024 due to higher sales volumes and the inclusion of thirteen months of expenses in the year ended December 31, 2024.

- Production, ad valorem and other taxes increased $1.2 million in 2024 compared to 2023, primarily due to the increased produced volumes.

- Development expenses increased $13.6 million due to several drilling and completion costs for drilling multiple new wells in the Permian and Haynesville areas during 2024.

During the year ended December 31, 2023, COERT fully released the total cash reserve of $1.0 million that it had previously established for approved, future development expenses. During the year ended December 31, 2024, the Sponsor withheld from the net profits otherwise payable to the Trust a net aggregate total of $1.0 million for the establishment of a cash reserve for approved, future development expenses. This reserve was intended to fund an expected increase in development expenses; however, if those expenses are ultimately delayed or are less than expected, or if the outlook changes, amounts reserved but unspent would be released as an incremental cash distribution in a future period. This cash reserve for future development was fully released to the Trust in early 2025.

The Trust withheld $1.6 million and paid $1.0 million for general and administrative expenses during the year ended December 31, 2024. Expenses paid during the period primarily consisted of fees for the preparation of 2023 tax information for Trust unitholders, preparation of the Trust's 2023 reserve report and Annual Report on Form 10-K, 2023 financial statement audit fees, preparation of the Trust's 2024 monthly press releases and Quarterly Reports on Form 10-Q, Trustee fees, and New York Stock Exchange listing fees. For the year ended December 31, 2023, the Trust withheld $1.3 million and paid $0.9 million for general and administrative expenses.

Liquidity and Capital Resources

The Trust's principal sources of liquidity are cash flow generated from the Net Profits Interest and borrowing capacity under the letter of credit described below. Other than Trust administrative expenses, including any reserves established by the Trustee for future liabilities, the Trust's only use of cash is for distributions to Trust unitholders. Available funds are the excess cash, if any, received by the Trust from the Net Profits Interest and other sources (such as interest earned on any amounts reserved by the Trustee) in any given month, over the Trust's expenses paid for that month. Available funds are reduced by any cash the Trustee determines to hold as a reserve against future expenses.

The Trustee may create a cash reserve to pay for future liabilities of the Trust. In November 2021, the Trustee notified COERT of the Trustee's intent to build a cash reserve for the payment of future known, anticipated or contingent expenses or liabilities of the Trust. From February 2022 through March 2023, the Trustee withheld $37,833, and commencing with the distribution to Trust unitholders paid in April 2023 has been withholding and, in the future, intends to withhold $50,000, from the funds otherwise available for distribution each month to gradually build a cash reserve of approximately $2.3 million. The Trustee may increase or decrease the targeted cash reserve amount at any time and may increase or decrease the rate at which it is withholding funds to build the cash reserve at any time, without advance notice to the Trust unitholders. Cash held in reserve will be invested as required by the Trust Agreement. Any cash reserved in excess of the amount necessary to pay or provide for the payment of future known, anticipated or contingent expenses or liabilities eventually will be distributed to Trust unitholders, together with interest earned on the funds. As of December 31, 2024, this cash reserve totaled $1,241,386.

If the Trustee determines that the cash on hand and the cash to be received are, or will be, insufficient to cover the Trust's liabilities, the Trustee may authorize the Trust to borrow money to pay administrative or incidental expenses of the Trust that exceed cash held by the Trust. The Trustee may authorize the Trust to borrow from any person, including the Trustee or the Delaware Trustee or an affiliate thereof, although none of the Trustee, the Delaware Trustee or any affiliate thereof intends to lend funds to the Trust. The Trustee may also cause the Trust to mortgage its assets to secure payment of the indebtedness. The terms of such indebtedness and security interest, if funds were to be loaned by the entity serving as Trustee or Delaware Trustee or an affiliate thereof, would be similar to the terms which such entity would grant to a similarly situated commercial customer with whom it did not have a fiduciary relationship. In addition, COERT has provided the Trust with a $1.2 million letter of credit to be used by the Trust if its cash on hand (including available cash reserves) is insufficient to pay ordinary course administrative expenses. Further, if the Trust requires more than the $1.2 million under the letter of credit to pay administrative expenses, COERT has agreed to loan funds to the Trust necessary to pay such expenses. Any loan made by COERT to the Trust would be evidenced by a written promissory note, be on an unsecured basis, and have terms that are no less favorable to COERT than those that would be obtained in an arm's length transaction between COERT and an unaffiliated third party. If the Trust borrows funds or draws on the letter of credit, no further distributions will be made to Trust unitholders until such amounts borrowed or drawn are repaid. Except for the foregoing, the Trust has no source of liquidity or capital resources. The Trustee has no current plans to authorize the Trust to borrow money other than Sponsor advances to pay the Trust's monthly operating expenses. At December 31, 2024 and 2023, the Trust held cash reserves of $2,193,787 and $1,394,697, respectively, for future Trust expenses. Since its formation, the Trust has not borrowed any funds other than Sponsor advances to pay the Trust's monthly operating expenses and no amounts have been drawn on the letter of credit.

From time to time, if the Trust's cash on hand (including available cash reserves, if any) is not sufficient to pay the Trust's ordinary course administrative expenses that are due prior to the monthly payment to the Trust of proceeds from the Net Profits Interest, the Sponsor may advance funds to the Trust to pay such expenses. Such advances are recorded as a liability on the Statements of Assets, Liabilities and Trust Corpus until repaid.

Cash held by the Trustee as a reserve against future liabilities or for distribution at the next distribution date may be held in a noninterest-bearing account or may be invested in:

- interest-bearing obligations of the United States government;
- money market funds that invest only in United States government securities;
- repurchase agreements secured by interest-bearing obligations of the United States government; or
- bank certificates of deposit.

The Sponsor has not entered into any hedge contracts relating to oil and natural gas volumes produced from the Underlying Properties, attributable to the Net Profits Interest for the years ended December 31, 2024 or 2023, and the terms of the Conveyance prohibit COERT from entering into new hedging arrangements burdening the Trust.

The Trust pays the Trustee an administrative fee of $200,000 per year. The Trust pays the Delaware Trustee an annual fee of $2,000. The Trust also incurs, either directly or as a reimbursement to the Trustee, legal, accounting, tax and engineering fees, printing costs and other expenses that are deducted by the Trust before distributions are made to Trust unitholders. The Trust also is responsible for paying other expenses incurred as a result of being a publicly traded entity, including costs associated with annual and quarterly reports to Trust unitholders, tax return and Form 1099 preparation and distribution, NYSE listing fees, independent auditor fees and registrar and transfer agent fees.

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.

New Accounting Pronouncements

As the Trust’s financial statements are prepared on the modified cash basis, most accounting pronouncements are not applicable to the Trust’s financial statements. No new accounting pronouncements have been adopted or issued that would impact the financial statements of the Trust.

Critical Accounting Policies and Estimates

The Trust uses the modified cash basis of accounting to report Trust receipts of income from the Net Profits Interest and payments of expenses incurred. The Net Profits Interest represents the right to receive revenues (oil and natural gas sales), less direct operating expenses (lease operating expenses and production and property taxes) and development expenses of the Underlying Properties plus any payments made or net payments received in connection with the settlement of certain hedge contracts, multiplied by 80%. Cash distributions of the Trust are made based on the amount of cash received by the Trust pursuant to terms of the Conveyance.

Under the terms of the Conveyance, the monthly Net Profits Interest calculation includes oil and natural gas revenues received. Monthly operating expenses and capital expenditures represent incurred expenses, and as a result, represent accrued expenses as well as expenses paid during the period.

The financial statements of the Trust are prepared on the following basis:

(a) Income from Net Profits Interest is recorded when distributions are received by the Trust;

(b) Distributions to Trust unitholders are recorded when paid by the Trust;

(c) Trust general and administrative expenses (which includes the Trustee’s fees as well as accounting, engineering, legal, and other professional fees) are recorded when paid;

(d) Cash reserves for Trust expenses may be established by the Trustee for certain future expenditures that would not be recorded as contingent liabilities under accounting principles generally accepted in the United States of America (“GAAP”);

(e) Amortization of the Net Profits Interest in oil and natural gas properties is calculated on a unit-of-production basis and is charged directly to the Trust corpus. Such amortization does not affect distributable income of the Trust; and

(f) The Net Profits Interest in oil and natural gas properties is periodically assessed whenever events or circumstances indicate that the aggregate value may have been impaired below its total capitalized cost based on the Underlying Properties. If an impairment loss is indicated by the carrying amount of the assets exceeding the sum of the undiscounted expected future net cash flows of the Net Profits Interest, then an impairment loss is recognized for the amount by which the carrying amount of the asset exceeds its estimated fair value determined using discounted cash flows.

The financial statements of the Trust differ from financial statements prepared in accordance with GAAP because revenues are not accrued in the month of production; certain cash reserves may be established for contingencies which would not be accrued in financial statements prepared in accordance with GAAP; general and administrative expenses are recorded when paid instead of when incurred; Any impairment; and amortization of the net profits interest calculated on a unit-of-production basis is charged directly to trust corpus instead of as an expense. While these statements differ from financial statements prepared in accordance with GAAP, the modified cash basis of reporting revenues, expenses, and distributions is considered to be the most meaningful because monthly distributions to the Trust unitholders are based on net cash receipts.

This comprehensive basis of accounting other than GAAP corresponds to the accounting permitted for royalty trusts by the SEC as specified by Staff Accounting Bulletin Topic 12:E, *Financial Statements of Royalty Trusts*.

The preparation of financial statements requires the Trust to make estimates and assumptions that affect the reported amounts of assets and liabilities and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

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

The Financial Accounting Standards Board requires supplemental disclosures for oil and gas producers based on a standardized measure of discounted future net cash flows relating to proved oil and natural gas reserve quantities. Under this disclosure, future cash inflows are computed by applying the average prices during the 12-month period prior to fiscal year-end, determined as an unweighted arithmetic average of the first-day-of-the-month benchmark price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. Future price changes are only considered to the extent provided by contractual arrangements in existence at year-end. The standardized measure of discounted future net cash flows is achieved by using a discount rate of 10% a year to reflect the timing of future cash flows relating to proved oil and natural gas reserves. Changes in any of these assumptions, including consideration of other factors, could have a significant impact on the standardized measure. The standardized measure does not necessarily result in an estimate of the current fair market value of proved reserves.

Amortization of Net Profits Interest. The Trust calculates amortization of the Net Profits Interest in oil and natural gas properties on a unit-of-production basis based on the Underlying Properties' production and reserves. The reserves upon which the amortization rate is based are quantity estimates which are subject to numerous uncertainties inherent in the estimation of proved reserves. The volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. These estimates are expected to change as additional information becomes available in the future. Downward revisions in proved reserves may result in an increased rate of amortization. Amortization is recorded on sales volumes paid by the Trust during the relevant period and is charged directly to the Trust corpus balance. As a result, amortization does not affect the cash earnings of the Trust.

Impairment of Net Profits Interest. The Net Profits Interest in oil and natural gas properties is periodically assessed for impairment whenever events or circumstances indicate that the current fair value based on expected future cash flows of the Underlying Properties may be less than the carrying value of the Net Profits Interest. The Trust did not realize any impairment during the years ended December 31, 2024 or 2023. Future downward revisions in actual production volumes relative to current forecasts, higher than expected operating costs, or lower than anticipated market pricing could result in recognition of impairment in future periods. Any impairment of the Net Profits Interest will result in a non-cash charge to Trust corpus and will not affect distributable income. For further information, see "Note 3. Net Profits Interest in Oil and Gas Properties" of the Notes to Financial Statements in Part II, Item 8 of this Form 10-K.

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

As a “smaller reporting company” as defined in Item 10(f)(1) of Regulation S-K, the Trust is not required to provide information required by this Item.

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

Report of Independent Registered Public Accounting Firm

To the Trustee and Unitholders of Permianville Royalty Trust:

Opinion on the Financial Statements

We have audited the accompanying statements of assets, liabilities and trust corpus of Permianville Royalty Trust (the Trust) as of December 31, 2024 and 2023, and the related statements of distributable income and changes in trust corpus for the years then ended, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Trust as of December 31, 2024 and 2023, and its distributable income and changes in trust corpus for the years then ended, in conformity with the modified cash basis of accounting, as described in Note 2, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America.

Basis of Accounting

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

Basis for Opinion

These financial statements are the responsibility of the Trustee. Our responsibility is to express an opinion on these 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 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 audit we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Trust's internal control over financial reporting. Accordingly, we express no such opinion.

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

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: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. We determined that there are no critical audit matters.

/s/ WEAVER AND TIDWELL, L.L.P.

We have served as the Trust's auditor since 2021.

Houston, Texas
March 19, 2025

PERMIANVILLE ROYALTY TRUST

Statements of Assets, Liabilities and Trust Corpus

	December 31,	
	2024	**2023**
ASSETS		
Cash and cash equivalents	$ 2,193,787	$ 1,394,697
Net profits interest in oil and natural gas properties, net	41,892,402	50,233,433
Total assets	$ 44,086,189	$ 51,628,130
LIABILITIES AND TRUST CORPUS		
Advances to the Trust	$ 150,000	-
Total liabilities	150,000	-
Trust corpus (33,000,000 units issued and outstanding)	43,936,189	51,628,130
Total liabilities and Trust corpus	$ 44,086,189	$ 51,628,130

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

PERMIANVILLE ROYALTY TRUST

Statements of Distributable Income

	Year Ended December 31,	
	2024	**2023**
Income from net profits interest	$ 4,259,281	$ 10,347,619
Income from sale/lease of assets	117,120	245,000
Income from sale of producing properties	-	4,848,281
Interest and investment income	80,032	63,142
General and administrative expenses	(985,843)	(919,148)
Cash reserves withheld for Trust expenses	(649,090)	(471,784)
Distributable income	$ 2,821,500	$ 14,113,110
Distributable income per unit (33,000,000 units)	$ 0.085500	$ 0.427670

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

PERMIANVILLE ROYALTY TRUST

Statements of Changes in Trust Corpus

	Year Ended December 31,	
	2024	**2023**
Trust corpus, beginning of period	$ 51,628,130	$ 60,564,545
Sale of net profits interest of producing properties	-	(4,163,851)
Cash reserves (used) withheld for Trust expenses	649,090	471,784
Distributable income	2,821,500	14,113,110
Distributions to unitholders	(2,821,500)	(14,113,110)
Amortization of net profits interest	(8,341,031)	(5,244,348)
Trust corpus, end of period	$ 43,936,189	$ 51,628,130

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

PERMIANVILLE ROYALTY TRUST
NOTES TO FINANCIAL STATEMENTS

1. TRUST ORGANIZATION AND PROVISIONS

Permianville Royalty Trust (the “Trust”), previously known as Enduro Royalty Trust, is a Delaware statutory trust formed in May 2011 pursuant to a trust agreement (as amended and restated, and as further amended, the “Trust Agreement”) among Enduro Resource Partners LLC (“Enduro”), as trustor, The Bank of New York Mellon Trust Company, N.A. (the “Trustee”), as trustee, and Wilmington Trust Company (the “Delaware Trustee”), as Delaware Trustee.

The Trust was created to acquire and hold for the benefit of the Trust unitholders a net profits interest representing the right to receive 80% of the net profits from the sale of oil and natural gas production from certain properties in the states of Texas, Louisiana and New Mexico held by Enduro as of the date of the conveyance of the net profits interest to the Trust (the “Net Profits Interest”). The properties in which the Trust holds the Net Profits Interest are referred to as the “Underlying Properties.”

In connection with the closing of the initial public offering in November 2011, Enduro contributed the Net Profits Interest to the Trust in exchange for 33,000,000 units of beneficial interest in the Trust (the “Trust Units”). Through the initial public offering in 2011 and a secondary offering in 2013, Enduro sold a total of 24,400,000 Trust Units. As of December 31, 2017, Enduro owned 8,600,000 Trust Units, or 26% of the issued and outstanding Trust Units.

At a special meeting of Trust unitholders held on August 30, 2017, unitholders approved several proposals, including amendments to the Trust Agreement. In September 2017, Enduro, the Trustee and the Delaware Trustee entered into the First Amendment to Amended and Restated Trust Agreement, which amended certain provisions of the Trust Agreement to, among other things, allow Enduro to sell interests in the Underlying Properties free and clear of the Net Profits Interest with the approval of Trust unitholders holding at least 50% of the then outstanding units of the Trust at a meeting held in accordance with the requirements of the Trust Agreement. This amendment reduced the required threshold for approval of such sales from 75% to 50% of the outstanding units of the Trust.

On August 31, 2018, COERT Holdings 1 LLC (“COERT” or the “Sponsor”) acquired the Underlying Properties and all of the outstanding Trust Units owned by Enduro (the “Sale Transaction”). In connection with the Sale Transaction, the Sponsor assumed all of Enduro’s obligations under the Trust Agreement and other instruments to which Enduro and the Trustee were parties. As of December 31, 2024, the Sponsor owned 7,363,961 Trust Units, or 22% of the issued and outstanding Trust Units.

The Net Profits Interest is passive in nature and neither the Trust nor the Trustee has any management control over or responsibility for costs relating to the operation of the Underlying Properties. The Trust has no directors, officers or employees. The business and affairs of the Trust are administered by The Bank of New York Mellon Trust Company, N.A., as Trustee. The duties of the Trustee are defined by the Trust Agreement. The Trustee does not make operating or business decisions affecting the assets of the Trust, and the Trustee’s functions under the Trust Agreement are ministerial in nature. The Trust Agreement provides, among other provisions, that:

- the Trust’s business activities are limited to owning the Net Profits Interest and any activity reasonably related to such ownership, including activities required or permitted by the terms of the Conveyance of Net Profits Interest, dated effective as of July 1, 2011 (as supplemented and amended to date, the “Conveyance”); as a result, the Trust is not permitted to acquire other oil and natural gas properties or net profits interests or otherwise to engage in activities beyond those necessary for the conservation and protection of the Net Profits Interest;

- the Trust may dispose of all or any material part of the assets of the Trust (including the sale of the Net Profits Interests) if approved by at least 75% of the outstanding Trust Units;

- the Sponsor may sell a divided or undivided portion of its interests in the Underlying Properties, free from and unburdened by the Net Profits Interest, if approved by at least 50% of the outstanding Trust Units at a meeting of Trust unitholders;

- the Trustee will make monthly cash distributions to Trust unitholders (Note 5);
- the Trustee may create a cash reserve to pay for future liabilities of the Trust;
- the Trustee may authorize the Trust to borrow money to pay administrative or incidental expenses of the Trust that exceed its cash on hand and available reserves; in that event, no further distributions will be made to Trust unitholders until such amounts borrowed are repaid; and
- the Trust is not subject to any pre-set termination provisions based on a maximum volume of oil or natural gas to be produced or the passage of time; the Trust will dissolve upon the earliest to occur of the following:
  - the Trust, upon approval of the holders of at least 75% of the outstanding Trust Units, sells the Net Profits Interest;
  - the annual cash proceeds received by the Trust attributable to the Net Profits Interest are less than $2 million for each of any two consecutive years;
  - the holders of at least 75% of the outstanding Trust Units vote in favor of dissolution; or
  - the Trust is judicially dissolved.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

The Trust uses the modified cash basis of accounting to report Trust receipts of income from the Net Profits Interest and payments of expenses incurred. The Net Profits Interest represents the right to receive revenues (oil and natural gas sales), less direct operating expenses (including lease operating expenses and production and property taxes) and development expenses of the Underlying Properties, multiplied by 80%. Cash distributions of the Trust are made based on the amount of cash received by the Trust from the Sponsor pursuant to terms of the Conveyance creating the Net Profits Interest.

Under the terms of the Conveyance, the monthly Net Profits Interest calculation includes oil and natural gas revenues received by the Sponsor during the relevant month. Monthly operating expenses and capital expenditures represent estimated incurred expenses, and as a result, represent accrued expenses as well as expenses paid during the period.

The financial statements of the Trust are prepared on the following basis:

(a) Income from Net Profits Interest is recorded when distributions are received by the Trust;

(b) Distributions to Trust unitholders are recorded when paid by the Trust;

(c) Trust general and administrative expenses (which includes the Trustee’s fees as well as accounting, engineering, legal, and other professional fees) are recorded when paid;

(d) Cash reserves for Trust expenses may be established by the Trustee for certain future expenditures that would not be recorded as contingent liabilities under accounting principles generally accepted in the United States of America (“GAAP”);

(e) Amortization of the Net Profits Interest in oil and natural gas properties is calculated on a unit-of-production basis and is charged directly to the Trust corpus; and

(f) The Net Profits Interest in oil and natural gas properties is periodically assessed whenever events or circumstances indicate that the aggregate value may have been impaired below its total capitalized cost based on the Underlying Properties. If an impairment loss is indicated by the carrying amount of the assets exceeding the sum of the undiscounted expected future net cash flows of the Net Profits Interest, then an impairment loss is recognized for the amount by which the carrying amount of the asset exceeds its estimated fair value determined using discounted cash flows.

The financial statements of the Trust differ from financial statements prepared in accordance with GAAP because revenues are not accrued in the month of production; certain cash reserves may be established for contingencies which would not be accrued in financial statements prepared in accordance with GAAP; general and administrative expenses are recorded when paid instead of when incurred; and amortization of the net profits interest calculated on a unit-of-production basis and any impairment recorded is charged directly to trust corpus instead of as an expense. While these statements differ from financial statements prepared in accordance with GAAP, the modified cash basis of reporting revenues, expenses, and distributions is considered to be the most meaningful because monthly distributions to the Trust unitholders are based on net cash receipts.

This comprehensive basis of accounting other than GAAP corresponds to the accounting permitted for royalty trusts by the U.S. Securities and Exchange Commission ("SEC") as specified by Staff Accounting Bulletin Topic 12:E, *Financial Statements of Royalty Trusts*.

Use of Estimates

The preparation of financial statements in conformity with the basis of accounting described above requires the Trust to make estimates and assumptions that affect reported amounts of assets and liabilities and the reported amounts of revenues and expenses during the reporting period. Significant estimates affecting these financial statements include estimates of proved oil and natural gas reserves, which are used to compute the Trust's amortization of net profits interest and its impairment assessments. Although the Trustee believes that these estimates are reasonable, actual results could differ from those estimates.

Cash and Cash Equivalents

Cash and cash equivalents include cash in banks, money market accounts, and all highly liquid investments with an original maturity of three months or less.

Impairment

The Net Profits Interest in oil and natural gas properties is periodically assessed for impairment whenever events or circumstances indicate that the current fair value based on expected future cash flows of the Underlying Properties may be less than the carrying value of the Net Profits Interest. While the Trust did not record an impairment during the years ended December 31, 2024 or 2023, future downward revisions in actual production volumes relative to current forecasts, higher than expected operating costs, or lower than anticipated commodity prices could result in recognition of impairment in future periods.

New Accounting Pronouncements

As the Trust's financial statements are prepared on the modified cash basis, most accounting pronouncements are not applicable to the Trust's financial statements. No new accounting pronouncements have been adopted or issued that would impact the financial statements of the Trust.

3. NET PROFITS INTEREST IN OIL AND NATURAL GAS PROPERTIES

The Net Profits Interest in oil and natural gas properties was recorded at its fair value on the date of conveyance. Amortization of the Net Profits Interest in oil and natural gas properties is calculated on a unit-of-production basis based on the Underlying Properties' production and reserves. The reserves upon which the amortization rate is based are quantity estimates which are subject to numerous uncertainties inherent in the estimation of proved reserves. The volumes considered to be commercially recoverable fluctuate with changes in commodity prices and operating costs. These estimates are expected to change as additional information becomes available in the future. Downward revisions in proved reserves may result in an increased rate of amortization. Amortization is charged directly to the Trust Corpus balance and does not affect the distributable income of the Trust. Accumulated amortization as of December 31, 2024 and 2023 was $311,034,905 and $302,693,874, respectively.

The Net Profits Interest is periodically assessed for impairment whenever events or circumstances indicate that the current fair value based on expected future cash flows of the Underlying Properties may be less than the carrying value of the Net Profits Interest. While the Trust did not record an impairment during the years ended December 31, 2024 or 2023, future downward revisions in actual production volumes relative to current forecasts, higher than expected operating costs, or lower than anticipated commodity prices could result in recognition of impairment in future periods.

Sale of 2023 Divestiture Properties

On May 3, 2023, the Sponsor notified the Trustee that the Sponsor had entered into an agreement to divest certain acreage and associated production in the Permian Basin (the "2023 Divestiture Properties") that constituted part of the Underlying Properties and were therefore burdened by the Trust's Net Profits Interest, for a total purchase price of approximately $6.7 million. On July 19, 2023, at a special meeting of Trust unitholders, the unitholders approved the foregoing transaction and the release of the Trust's Net Profits Interest in the 2023 Divestiture Properties. On August 9, 2023, the Sponsor completed the sale of the 2023 Divestiture Properties, and the Trustee, on behalf of the Trust, reconveyed, terminated and released to the Sponsor the Net Profits Interest with respect to the 2023 Divestiture Properties. The total proceeds received by the Sponsor from the 2023 Divestiture Properties, after preliminary closing adjustments, were approximately $6.5 million, inclusive of the escrow funded by the buyer and partial expense reimbursement associated with the proxy solicitation. the Sponsor deducted the final transaction expenses from the sales proceeds, along with an escrow amount of $250,000 to cover possible indemnification obligations under the purchase and sale agreement (the "Indemnification Escrow Amount"), to arrive at final net proceeds, based upon the Trust's Net Profits Interest.

On September 20, 2023, the Trust announced a special cash distribution to Trust unitholders of $0.069670 per Trust Unit, payable on October 13, 2023 to Trust unitholders of record on October 2, 2023, reflecting 50% of the Trust's share of the net proceeds, after accounting for the Indemnification Escrow Amount. The following table displays the aggregate net proceeds from the sale of the 2023 Divestiture Properties and the aggregate net proceeds allocable to Trust unitholders for this distribution:

Net Proceeds from sale of 2023 Divestiture Properties	$ 6,712,000
Less: Transaction expenses	(627,149)
Plus: Buyer proxy expense reimbursement	288,000
Net proceeds from sale of 2023 Divestiture Properties	**$ 6,372,851**
Less: Amount allocable to the Sponsor's 20% interest	(1,274,570)
Net proceeds allocable to the Trust's 80% Interest	$ 5,098,281
Less: Indemnification Escrow amount	(250,000)
Less: Estimated Settlement Escrow amount	(2,549,140)
Initial Cash available for distribution by the Trust	**$ 2,299,141**
Number of units	33,000,000
Initial special cash distribution per unit	**$ 0.069670**

The remaining 50% of the Trust's share of the net proceeds was temporarily retained by the Sponsor as a source of payment of the Trust's proportionate share of any post-closing purchase price adjustments, with any amount remaining (less any amounts in dispute) after such adjustments to be paid to the Trust within five business days after finalization of the settlement statement and included in a distribution to Trust unitholders.

On November 6, 2023, the Trust announced a special cash distribution to Trust unitholders of $0.077250 per Trust Unit, payable on November 22, 2023 to Trust unitholders of record on November 16, 2023, reflecting the remaining 50% of the Trust's share of the net proceeds (net of the Indemnification Escrow Amount). The following table displays the aggregate net proceeds from the sales of the 2023 Divestiture Properties and the aggregate net proceeds allocable to Trust unitholders for this distribution:

Net Proceeds from sale of 2023 Divestiture Properties	$ 6,712,000
Less: Transaction expenses	(627,149)
Plus: Buyer proxy expense reimbursement	288,000
Net proceeds from sale of 2023 Divestiture Properties	**$ 6,372,851**
Less: Amount allocable to the Sponsor's 20% interest	(1,274,570)
Net proceeds allocable to the Trust's 80% Interest	$ 5,098,281
Less: Indemnification Escrow amount	(250,000)
Less: October 13, 2023 Initial Cash Distribution	(2,299,110)
Remaining cash available for distribution by the Trust	**$ 2,549,171**
Number of units	33,000,000
Remaining special cash distribution per unit	**$ 0.077250**

See "Note 7. Subsequent Event" for information regarding the release of the Indemnification Escrow Amount and its inclusion in a special distribution to Trust unitholders.

Impairment of Net Profits Interest

Fair value accounting guidance includes a hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 inputs) and the lowest priority to unobservable inputs (Level 3). When indicators of impairment are present and it is determined that the carrying value of the Net Profits Interest exceeds the estimated undiscounted cash flows of the subject interest, fair value estimates utilized in the impairment assessment are determined based on inputs not observable in the market and thus represent Level 3 measurements.

4. INCOME TAXES

Federal Income Taxes

For federal income tax purposes, the Trust is a grantor trust and therefore is not subject to tax at the trust level. Trust unitholders are treated as owning a direct interest in the assets of the Trust, and each Trust unitholder is taxed directly on his or her pro rata share of the income and gain attributable to the assets of the Trust and entitled to claim his or her pro rata share of the deductions and expenses attributable to the assets of the Trust. 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 rather than when distributed by the Trust.

The deductions of the Trust consist of severance taxes and administrative expenses. In addition, each unitholder is entitled to depletion deductions because the Net Profits Interest constitutes "economic interests" in oil and natural gas properties for federal income tax purposes. Each unitholder is entitled to amortize the cost of the Trust Units through cost depletion over the life of the Net Profits Interest or, if greater, through percentage depletion. Unlike cost depletion, percentage depletion is not limited to a unitholder's depletable tax basis in the Trust Units. Rather, a unitholder could be entitled to percentage depletion as long as the applicable Underlying Properties generate net income.

Some Trust Units are held by a middleman, 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 custodian in street name). Therefore, the Trustee considers the Trust to be a non-mortgage widely held fixed investment trust ("WHFIT") for U.S. federal income tax purposes. The Bank of New York Mellon Trust Company, N.A., 601 Travis, 16th Floor, Houston, Texas 77002, telephone number (512) 236-6545, 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.permianvilleroyaltytrust.com. Notwithstanding the foregoing, the middlemen holding 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 units, including the issuance of IRS Forms 1099 and certain written tax statements. Trust unitholders whose 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.

The tax consequences to a unitholder of ownership of Trust Units will depend in part on the unitholder's tax circumstances. Trust unitholders should consult their tax advisors about the federal tax consequences relating to owning the Trust Units.

State Taxes

The Trust's revenues are from sources in the states of Louisiana, New Mexico and Texas. Because it distributes all of its net income to unitholders, the Trust is not taxed at the trust level in Louisiana or New Mexico. Although the Trust does not owe tax, the Trustee is required to file a return with Louisiana reflecting the income and deductions of the Trust attributable to properties located in that state. Louisiana and New Mexico presently have income taxes which tax income of nonresidents from real property located within that state. Louisiana and New Mexico also impose a corporate income tax which may apply to unitholders organized as corporations.

Texas imposes a franchise tax at a rate of 0.75% on gross revenues less certain deductions for returns originally due on or after January 1, 2016, as specifically set forth in the Texas franchise tax statutes. Entities subject to tax generally include trusts unless otherwise exempt. Trusts that receive at least 90% of their federal gross income from designated passive sources, including royalties from mineral properties and other income from other non-operating mineral interests, and do not receive more than 10% of their income from operating an active trade or business, generally are exempt from the Texas franchise tax as "passive entities." Although the Trust is intended to be exempt from Texas franchise tax at the trust level as a passive entity, each unitholder that is considered a taxable entity under the Texas franchise tax would generally be required to include its portion of Trust net income in its own Texas franchise tax computation.

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

5. DISTRIBUTIONS TO UNITHOLDERS

Each month, the Trustee determines the amount of funds available for distribution to the Trust unitholders. Available funds are the excess cash, if any, received by the Trust from the Net Profits Interest and other sources (such as interest earned on any amounts reserved by the Trustee) that month, over the Trust's liabilities for that month, subject to adjustments for changes made by the Trustee during the month in any cash reserves established for future liabilities of the Trust. Distributions are made to the holders of Trust Units as of the applicable record date (generally the last business day of each calendar month) and are payable on or before the tenth business day after the record date.

The following table provides information regarding the Trust's distributions paid during the periods indicated:

Declaration Date	Record Date	Payment Date	Distribution per Unit
2024:			
July 18, 2024	July 31, 2024	August 14, 2024	$ 0.011000
August 16, 2024	August 30, 2024	September 16, 2024	$ 0.035000
September 16, 2024	September 30, 2024	October 15, 2024	$ 0.014000
October 18, 2024	October 31, 2024	November 15, 2024	$ 0.015000
November 18, 2024	November 29, 2024	December 13, 2024	$ 0.010500
Total—2024			**$ 0.085500**
2023:			
December 16, 2022	December 30, 2022	January 14, 2023	$ 0.058000
January 18, 2023	January 31, 2023	February 14, 2023	$ 0.056000
February 17, 2023	February 28, 2023	March 13, 2023	$ 0.019200
March 16, 2023	March 31, 2023	April 14, 2023	$ 0.019350
April 17, 2023	April 28, 2023	May 12, 2023	$ 0.030000
May 15, 2023	May 31, 2023	June 14, 2023	$ 0.013500
June 16, 2023	June 30, 2023	July 14, 2023	$ 0.012500
July 17, 2023	July 31, 2023	August 14, 2023	$ 0.053500
August 18, 2023	August 31, 2023	September 15, 2023	$ 0.009000
September 18, 2023	September 29, 2023	October 13, 2023	$ 0.003700
September 20, 2023 – Special Distribution	October 02, 2023	October 13, 2023	$ 0.069670
October 16, 2023	October 31, 2023	November 13, 2023	$ 0.006000
November 06, 2023 – Special Distribution	November 16, 2023	November 22, 2023	$ 0.077250
Total—2023			**$ 0.427670**

6. TRUSTEE FEES AND RELATED PARTY TRANSACTIONS

Trustee Administrative Fee. Under the terms of the Trust Agreement, the Trust pays an annual administrative fee of $200,000 to the Trustee and $2,000 to the Delaware Trustee. During the years ended December 31, 2024 and 2023, the Trust paid $200,000 and $200,000, respectively, to the Trustee and $0 and $2,010, respectively, to the Delaware Trustee pursuant to the terms of the Trust Agreement.

Letter of Credit. Under the terms of the Trust Agreement, COERT has provided the Trust with a $1,200,000 letter of credit to be used by the Trust if its cash on hand (including available cash reserves) is not sufficient to pay ordinary course administrative expenses. The letter of credit is issued to the benefit of the Trustee. The standby letter of credit was issued by West Texas National Bank and matures on December 31, 2025. The letter of credit to the Trustee is unfunded as of December 31, 2024.

Advances from COERT. From time to time, if the Trust's cash on hand (including available cash reserves, if any) is not sufficient to pay the Trust's ordinary course administrative expenses that are due prior to the monthly payment to the Trust of proceeds from the Net Profits Interest, COERT may advance funds to the Trust to pay such expenses. Such advances are recorded as a liability on the Statements of Assets, Liabilities and Trust Corpus until repaid. As of December 31, 2024 and 2023, advances to the Trust were $150,000 and $0, respectively.

Registration Rights Agreement. The Trust and COERT (as the assignee of Enduro, in connection with the Sale Transaction) are parties to a Registration Rights Agreement, as amended, whereby COERT, its affiliates and certain permitted transferees holding registrable Trust Units are entitled, upon receipt by the Trustee of written notice from holders of a majority of the then outstanding registrable Trust Units, to demand that the Trust effect the registration of the registrable Trust Units. The holders of the registrable Trust Units are entitled to demand a maximum of five such registrations. In connection with the preparation and filing of any registration statement, COERT will bear all costs and expenses incidental to any registration statement, excluding certain internal expenses of the Trust, which will be borne by the Trust. Any underwriting discounts and commissions will be borne by the seller of the Trust Units.

On June 22, 2022, pursuant to the Registration Rights Agreement, the Trust filed a registration statement on Form S-3 registering the offering by COERT of up to 8,600,000 Trust Units. The registration statement was declared effective on July 7, 2022.

7. SUBSEQUENT EVENT

On March 17, 2025, the Trust announced a special cash distribution to Trust unitholders of $0.008548 per Trust Unit, payable on April 14, 2025 to Trust unitholders of record on March 31, 2025, reflecting the release of the Indemnification Escrow Amount withheld in connection with the sale of the 2023 Divestiture Properties discussed in Note 3 above, together with interest, for a total of $282,072.

8. SUPPLEMENTARY OIL AND NATURAL GAS INFORMATION (UNAUDITED)

Oil and Natural Gas Reserve Quantities

Estimates of proved reserves attributable to the Trust and the related valuations were based 100% on reports prepared by the Trust's independent petroleum engineers, Cawley, Gillespie & Associates, Inc. Estimates were prepared in accordance with guidelines prescribed by the SEC and the Financial Accounting Standards Board, which require that reserve estimates be prepared under existing economic and operating conditions based upon an average of the first-day-of-the-month commodity price during the 12-month period ending on the balance sheet date with no provision for price and cost escalations except by contractual arrangements. Prices used in estimating reserves were as follows:

	2024	2023
Oil (per Bbl)	$ 75.48	$ 78.22
Natural gas (per MMBTU)	$ 2.13	$ 2.64

Proved reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revisions of previous estimates. Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The process of estimating quantities of oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reserve. Consequently, these estimates are expected to change as additional information becomes available in the future.

As of December 31, 2024 and 2023, all of the Underlying Properties' oil and natural gas reserves were attributable to properties within the United States. Proved reserves attributable to the Trust and related standardized measure valuations are prepared on an accrual basis, which is the basis on which Enduro and, following the Sale Transaction, the Sponsor, and the Underlying Properties maintain their production records and is different from the basis on which the Trust production records are computed. The following is a summary of the changes in quantities of proved oil and natural gas reserves attributable to the Trust for the periods indicated:

	Trust Net Profits Interest		
	Oil [(1)] (MBbls)	**Natural Gas (MMcf)**	**Total (MBOE)**
Balance—January 1, 2023	3,976	8,493	5,392
Extensions and discoveries	386	6,584	1,483
Revisions of previous estimates	(1,234)	(2,815)	(1,703)
Divestiture of Reserves	(525)	(126)	(546)
Income from Net Profits Interest	(440)	(2,782)	(904)
Balance—December 31, 2023	2,163	9,354	3,722
Extensions and discoveries	353	9,295	1,902
Revisions of previous estimates	858	1,075	1,037
Income from Net Profits Interest	(635)	(5,580)	(1,565)
Balance—December 31, 2024	2,739	14,144	5,096
Proved developed reserves:			
December 31, 2023	1,880	7,706	3,164
December 31, 2024	2,441	13,182	4,638
Proved undeveloped reserves:			
December 31, 2023	283	1,648	558
December 31, 2024	298	962	458

(1) Reserves for natural gas liquids are immaterial and included as a component of oil reserves.

Revisions of previous estimates. During the year ended December 31, 2024, revisions of previous estimates increased oil reserves by 40%.The NYMEX average oil price of $75.48 per Bbl used to determine reserves as of December 31, 2024 was 4% lower than the $78.22 per Bbl average NYMEX oil price as of December 31, 2023.

During the year ended December 31, 2023, revisions of previous estimates decreased oil reserves by 31%, primarily due to a decrease in the average oil price used to estimate future net reserves. The NYMEX average oil price of $78.22 per Bbl used to determine reserves as of December 31, 2023 was 16% lower than the $93.67 per Bbl average NYMEX oil price as of December 31, 2022.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves is computed by applying commodity prices used in determining proved reserves (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved reserves less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, discounted using a rate of 10% per year to reflect the estimated timing of the future cash flows. Future cash inflows were computed by applying the commodity prices utilized in determining proved reserves to estimated future production. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at year-end, based on year-end costs and assuming continuation of existing economic conditions. As the Trust is not subject to federal income taxes, future income taxes have been excluded.

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves attributable to the Trust was as follows as of the dates indicated:

	December 31,	
	2024	2023
	(in thousands)	
Future cash inflows	$ 197,669	$ 165,087
Future production taxes	(15,945)	(13,316)
Future net cash flows	$ 181,724	$ 151,771
10% annual discount for estimated timing of cash flows	(90,362)	(75,115)
Standardized measure of discounted future net cash flows	$ 91,362	$ 76,656

The changes in standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves attributable to the Trust for the periods indicated were as follows (in thousands):

	Year Ended December 31,	
	2024	2023
Extensions, discoveries, and other additions	$ 13,869	$ 12,709
Accretion of discount	7,666	16,316
Revisions of previous estimates and other	(2,569)	(97,416)
Divestiture of reserves	–	(7,765)
Income from Net Profits Interest	(4,259)	(10,348)
Change in present value of future net revenues	14,706	(86,504)
Balance, beginning of period	76,656	163,160
Balance, end of year	$ 91,362	$ 76,656

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

Not applicable.

Item 9A. ***Controls and Procedures.***

Evaluation of Disclosure Controls and Procedures. The Trustee conducted an evaluation of the Trust's disclosure controls and procedures (as defined in Rules 13a-15 and 15d-15 under the Exchange Act). Based on this evaluation, the Trustee has concluded that the disclosure controls and procedures of the Trust were effective, as of the end of the period covered by this report, in ensuring that information required to be disclosed by the Trust in the reports that it files or submits under the Exchange Act is accumulated and communicated to the Trustee to allow timely decisions regarding required disclosure.

Due to the nature of the Trust as a passive entity and in light of the contractual arrangements pursuant to which the Trust was created, including the provisions of (i) the Trust Agreement and (ii) the Conveyance, the Trustee's disclosure controls and procedures related to the Trust necessarily rely on (A) information provided by COERT, including information relating to results of operations, the costs and revenues attributable to the Trust's interest under the Conveyance and other operating and historical data, plans for future operating and capital expenditures, reserve information, information relating to projected production, and other information relating to the status and results of operations of the Underlying Properties and the Net Profits Interest, and (B) conclusions and reports regarding reserves by the Trust's independent reserve engineers.

Changes in Internal Control over Financial Reporting. During the quarter ended December 31, 2024, there were no changes in the Trust's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Trust's internal control over financial reporting. The Trustee notes for purposes of clarification that it has no authority over, and makes no statement concerning, the internal control over financial reporting of COERT.

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 Exchange Act. Internal control over financial reporting is a process to provide reasonable assurance regarding the reliability of financial reporting for external purposes in accordance with the modified cash basis of accounting. 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, 2024.

Item 9B. ***Other Information.***

Rule 10b5-1 Trading Plans. During the three months ended December 31, 2024, no officer or employee of the Trustee who performs policy-making functions for the Trust adopted, modified, or terminated any Rule 10b5-1 trading arrangement or non-Rule 10b5-1 trading arrangement, as such terms are defined in Item 408(a) of Regulation S-K, with respect to the Trust Units.

Item 9C. ***Disclosure Regarding Foreign Jurisdictions that Prevent Inspections.***

Not applicable.

PART III

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

The Trust has no directors or executive officers. The Trustee is a corporate trustee that may be removed by the affirmative vote of the holders of not less than a majority of the outstanding Trust Units at a meeting at which a quorum is present.

Audit Committee and Nominating Committee

Because the Trust does not have a board of directors, it does not have an audit committee, an audit committee financial expert or a nominating committee.

Code of Ethics

The Trust does not have a principal executive officer, principal financial officer, principal accounting officer or controller and has not adopted a code of ethics applicable to such persons.

Insider Trading Policy

Because the Trust has no directors, officers or employees, and because the Trustee does not have the authority under the terms of the Trust Agreement to engage in transactions in the Trust Units on behalf of the Trust, the Trust has not adopted an insider trading policy applicable to such persons or to the Trust itself. It is the policy of the Trustee that any transaction in Trust Units by any officer or employee of the Trustee who performs policy-making functions for the Trust must comply with the insider trading policies of The Bank of New York Mellon Corporation, the parent corporation of The Bank of New York Mellon Trust Company, N.A.

Item 11. ***Executive Compensation.***

Pursuant to the Trust Agreement, the Trust pays an annual administrative fee of $200,000 to the Trustee. During the years ended December 31, 2024 and 2023, the Trustee received $200,000, respectively, in administrative fees and reimbursable expenses from the Trust. The Trust does not have any executive officers, directors or employees. The Trust does not have a board of directors, and it does not have a compensation committee.

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

(a) Security Ownership of Certain Beneficial Owners.

Based on filings with the SEC, the Trustee is not aware of any holders of 5% or more of the Trust Units as of March 19, 2025 except as set forth below. The following information has been obtained from public filings with the SEC.

Beneficial Owner	Trust Units Beneficially Owned	Percent of Class
Permianville Holdings LLC	7,363,961(1)	22.3%
Jerry Roger Kent	1,722,300(2)	5.2%

(1) Based on a Form 4 dated August 17, 2023 filed by Permianville Holdings LLC (“Holdings”). The principal business office address for Holdings is 60 Arch Street, 3rd Floor, Greenwich, CT 06830.

(2) Based on a Schedule 13G/A filed with the SEC on June 23, 2023 by Jerry Roger Kent. The principal business office address for the reporting person is 4695 Preston Park Blvd., Suite 170 East, Plano, Texas 75093-5180. According to the filing, the reporting person has sole voting power with respect to 1,507,300 Trust Units, shared voting power with respect to 215,000 Trust Units, sole dispositive power with respect to 1,507,300 Trust Units, and shared dispositive power with respect to 215,000 Trust Units.

(b) Security Ownership of Management.

Not applicable.

(c) Changes in Control.

The registrant knows of no arrangement, including any pledge by any person of securities of the registrant or any of its parents, the operation of which may at a subsequent date result in a change of control of the registrant. See “Certain Relationships and Related Transactions, and Director Independence—Registration Rights Agreement” in Part III, Item 13 of this Form 10-K.

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

Trustee Administrative Fee. Under the terms of the Trust Agreement, the Trust pays an annual administrative fee of $200,000 to the Trustee and $2,000 to the Delaware Trustee.

Registration Rights Agreement. The Trust and COERT (as the assignee of Enduro in connection with the Sale Transaction) are parties to a Registration Rights Agreement, as amended, whereby COERT, its affiliates and certain permitted transferees holding registrable Trust Units are entitled, upon receipt by the Trustee of written notice from holders of a majority of the then outstanding registrable Trust Units, to demand that the Trust effect the registration of the registrable Trust Units. The holders of the registrable Trust Units are entitled to demand a maximum of five such registrations. In connection with the preparation and filing of any registration statement, COERT will bear all costs and expenses incidental to any registration statement, excluding certain internal expenses of the Trust, which will be borne by the Trust. Any underwriting discounts and commissions will be borne by the seller of the Trust Units. The foregoing description of the Registration Rights Agreement is qualified in its entirety by the terms of the Registration Rights Agreement, and Amendment No. 1 thereto, copies of which are incorporated by reference as exhibits to this Form 10-K.

On June 22, 2022, pursuant to the Registration Rights Agreement, the Trust filed a registration statement on Form S-3 registering the offering by COERT of 8,600,000 Trust Units. The registration statement was declared effective on July 7, 2022.

Director Independence

The Trust does not have a board of directors.

Item 14. *Principal Accountant Fees and Services.*

The Trust does not have an audit committee. Any pre-approval and approval of all services performed by the principal auditor or any other professional service firms and related fees are granted by the Trustee. The Trustee has appointed Weaver and Tidwell, LLP as the independent registered public accounting firm to audit the Trust’s financial statements for the fiscal year ending December 31, 2024. During the years ended December 31, 2024 and 2023, Weaver and Tidwell, LLP served as the Trust’s independent registered public accounting firm.

The following table presents the aggregate fees paid by the Trust for the years ended December 31, 2024 and 2023 by Weaver and Tidwell, LLP:

	2024	2023
Audit fees(1)	$ 108,215	$ 71,535
Audit-related fees	—	—
Tax fees	—	—
All other fees	—	—
Total fees	$ 108,215	$ 71,535

(1) Fees billed for professional services rendered for the audit of the Trust’s financial statements and reviews of the financial statements included in the Trust’s quarterly reports and annual financial statements.

PART IV

Item 15. ***Exhibit and Financial Statement Schedules.***

(a)(1) Financial Statements

The following financial statements are set forth under "Financial Statements and Supplementary Data" in Part II, Item 8 of this Form 10-K on the pages indicated:

(a)(2) Schedules

Schedules have been omitted because they are not required, not applicable or the information required has been included elsewhere herein.

(a)(3) Exhibits

See Index to Exhibits.

Item 16. ***Form 10-K Summary.***

None.

INDEX TO EXHIBITS

Exhibit Number	Description
2.1*	Agreement and Plan of Merger of Enduro Royalty Trust and Enduro Texas LLC, dated as of November 3, 2011 by and between the Bank of New York Mellon Trust Company, N.A., as Trustee of Enduro Royalty Trust, and Enduro Texas LLC. (Incorporated herein by reference to Exhibit 1.2 to the Trust's Current Report on Form 8-K filed on November 8, 2011 (File No. 1-35333))
3.1*	Certificate of Trust of Enduro Royalty Trust. (Incorporated herein by reference to Exhibit 3.3 to the Registration Statement on Form S-1, filed on May 16, 2011 (Registration No. 333-174225))
3.2*	Certificate of Amendment to Certificate of Trust. (Incorporated herein by reference to Exhibit 3.1 to the Trust's Current Report on Form 8-K filed on September 5, 2018 (File No. 1-35333))
3.3*	Amended and Restated Trust Agreement of Enduro Royalty Trust, dated as of November 3, 2011, among Enduro Resource Partners LLC, The Bank of New York Mellon Trust Company, N.A., as Trustee of Enduro Royalty Trust, and Wilmington Trust Company, as Delaware Trustee of Enduro Royalty Trust. (Incorporated herein by reference to Exhibit 3.1 to the Trust's Current Report on Form 8-K filed on November 8, 2011 (File No. 1-35333))
3.4*	First Amendment to Amended and Restated Trust Agreement, dated September 6, 2017 but effective as of August 30, 2017, among Enduro Resource Partners LLC, Wilmington Trust Company, as Delaware Trustee, and The Bank of New York Mellon Trust Company, N.A., as Trustee. (Incorporated herein by reference to Exhibit 3.1 to the Trust's Current Report on Form 8-K filed on September 12, 2017 (File No. 1-35333))
3.5*	Second Amendment to Amended and Restated Trust Agreement of Enduro Royalty Trust, dated September 14, 2018, among COERT Holdings 1 LLC, Wilmington Trust Company, as Delaware trustee, and The Bank of New York Mellon Trust Company, N.A., as trustee. (Incorporated herein by reference to Exhibit 3.1 to the Trust's Current Report on Form 8-K filed on September 14, 2018 (File No. 1-35333))
4.1*	Registration Rights Agreement, dated as of November 8, 2011, by and between Enduro Resource Partners LLC and Enduro Royalty Trust. (Incorporated herein by reference to Exhibit 10.3 to the Trust's Current Report on Form 8-K filed on November 8, 2011 (File No. 1-35333))
4.2*	Amendment No. 1 to Registration Rights Agreement, dated as of November 8, 2012, by and between Enduro Resource Partners LLC and Permianville Royalty Trust. (Incorporated herein by reference to Exhibit 4.2 to the Trust's Annual Report on Form 10-K for the year ended December 31, 2012 (File no. 1-35333))
4.3*	Description of Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934. (Incorporated herein by reference to Exhibit 4.3 to the Trust's Annual Report on Form 10-K for the year ended December 31, 2019 (File No. 1-35333))
10.1*	Conveyance of Net Profits Interest, dated November 8, 2011, by and between Enduro Operating LLC and Enduro Texas LLC. (Incorporated herein by reference to Exhibit 10.1 to the Trust's Current Report on Form 8-K filed on November 8, 2011 (File No. 1-35333))
10.2*	Supplement to Conveyance of Net Profits Interest, dated November 8, 2011, from Enduro Operating LLC, Enduro Texas LLC and The Bank of New York Mellon Trust Company, N.A. as Trustee of Enduro Royalty Trust. (Incorporated herein by reference to Exhibit 10.2 to the Trust's Current Report on Form 8-K filed on November 8, 2011 (File No. 1-35333))
10.3*	First Amendment to Conveyance of Net Profits Interest, dated September 6, 2017, among Enduro Operating LLC and The Bank of New York Mellon Trust Company, N.A., as Trustee of Enduro Royalty Trust. (Incorporated herein by reference to Exhibit 10.1 to the Trust's Current Report on Form 8-K filed on September 12, 2017 (File No. 1-35333))
10.4*	Partial Release, Reconveyance and Termination Agreement, dated September 6, 2017, by and between The Bank of New York Mellon Trust Company, N.A., as Trustee of Enduro Royalty Trust, and Enduro Operating LLC. (Incorporated herein by reference to Exhibit 10.2 to the Trust's Current Report on Form 8-K filed on September 12, 2017 (File No. 1-35333))
23.1	Consent of Cawley, Gillespie & Associates, Inc.
23.2	Consent of Weaver and Tidwell, L.L.P.
31.1	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
97.1*	Permianville Royalty Trust Clawback Policy (Incorporated herein by reference to Exhibit 97.1 to the Trust's Annual Report on Form 10-K for the year ended December 31, 2023 (File No. 1-35333))
99.1	Report of Cawley, Gillespie & Associates, Inc.

* Asterisk indicates exhibit previously filed with the SEC and incorporated herein by reference.

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.

Date: March 19, 2025

PERMIANVILLE ROYALTY TRUST

By: THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A., AS TRUSTEE

By: /s/ SARAH NEWELL
Name: Sarah Newell
Title: Vice President

The Registrant, Permianville Royalty Trust, has no principal executive officer, principal financial officer, board of directors or persons performing similar functions. Accordingly, no additional signatures are available and none have been provided. In signing the report above, the Trustee does not imply that it has performed any such function or that such function exists pursuant to the terms of the Trust Agreement under which it serves.

Exhibit 23.1

CAWLEY, GILLESPIE & ASSOCIATES, INC.

PETROLEUM CONSULTANTS

13640 BRIARWICK DRIVE, SUITE 100 AUSTIN, TEXAS 78729-1707 512-249-7000	306 WEST SEVENTH STREET, SUITE 302 FORT WORTH, TEXAS 76102-4987 817- 336-2461 www.cgaus.com	1000 LOUISIANA STREET, SUITE 1900 HOUSTON, TEXAS 77002-5008 713-651-9944

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the use of the oil and gas reserve information in the Permianville Royalty Trust Securities and Exchange Commission Form 10-K for the year ended December 31, 2024, based on the reserve report dated January 31, 2024. We also consent to the inclusion of our report dated January 31, 2024 as an exhibit to the Form 10-K and to the incorporation by reference of such report in Permianville Royalty Trust's Registration Statement on Form S-3 (Registration No. 333-265777).

W. Todd Brooker

W. Todd Brooker, P.E.
Senior Vice President
Cawley, Gillespie & Associates, Inc.
Texas Registered Engineering Firm F-693

Fort Worth, Texas
March 19, 2025

Exhibit 23.2

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statement (Form S-3 No. 333-265777) of Permianville Royalty Trust of our report dated March 19, 2025, with respect to the financial statements of Permianville Royalty Trust, included in this Annual Report (Form 10-K) for the year ended December 31, 2024 and 2023.

/s/ Weaver and Tidwell, L.L.P.

Weaver and Tidwell, L.L.P.
Houston, Texas
March 19, 2025

EXHIBIT 31.1

CERTIFICATION

I, Sarah Newell, certify that:

1. I have reviewed this annual report on Form 10-K of Permianville Royalty Trust, for which The Bank of New York Mellon Trust Company, N.A., 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)), or for causing such controls and procedures to be established and maintained, for the registrant and I have:

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

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

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

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

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

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

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

In giving the foregoing certifications in paragraphs 4 and 5, I have relied to the extent I consider reasonable on information provided to me by COERT Holdings 1 LLC

Date: March 19, 2025

/s/ SARAH NEWELL
Sarah Newell
Vice President
The Bank of New York Mellon Trust Company, N.A., as Trustee

EXHIBIT 32.1

March 19, 2025

Via EDGAR

Securities and Exchange Commission
100 F Street, N.E.
Washington, D.C. 20549

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

Ladies and Gentlemen:

In connection with the Annual Report of Permianville Royalty Trust (the "Trust") on Form 10-K for the year ended December 31, 2024 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, not in its individual capacity but solely as the Trustee of the Trust, certifies pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to its knowledge:

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

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

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

The Bank of New York Mellon Trust Company,
N.A., Trustee for Permianville Royalty Trust

By: /s/ SARAH NEWELL
Sarah Newell
Vice President and Trust Officer

Exhibit 99.1

CAWLEY, GILLESPIE & ASSOCIATES, INC.

PETROLEUM CONSULTANTS

13640 BRIARWICK DR., SUITE 100
AUSTIN, TEXAS 78729-1106
512-249-7000

306 WEST SEVENTH STREET, SUITE 302
FORT WORTH, TEXAS 76102-4987
817- 336-2461
www.cgaus.com

1000 LOUISIANA STREET, SUITE 1900
HOUSTON, TEXAS 77002-5008
713-651-9944

February 12, 2025

Ms. Sarah Newell
Permianville Royalty Trust
The Bank of New York Mellon Trust Company, N.A., Trustee
601 Travis Street
16th Floor
Houston Texas, 77002

Re: Evaluation—Total Proved Reserves
Permianville Royalty Trust Net Profit Interests
Derived From Permianville Resource Partners LLC
Underlying Properties Total Controlled Interests
Texas, Louisiana and New Mexico Properties
Using Year-end SEC Prices as of December 31, 2024

Pursuant to the Guidelines of the Securities and Exchange Commission for Reporting Corporate Reserves and Future Net Revenue

Dear Ms. Newell:

As requested, this report was prepared on February 12, 2025 for Permianville Royalty Trust ("Trust") for the purpose of submitting our estimates of total proved reserves and forecasts of economics attributable to the Trust net profits interests. We evaluated 100% of the Trust reserves, which are made up of oil and gas properties in Texas, Louisiana and New Mexico controlled by COERT Holdings 1, LLC ("Company"). This evaluation utilized an effective date of December 31, 2024, was prepared using constant prices and costs, and conforms to Item 1202(a)(8) of Regulation S-K and other rules of the *Securities and Exchange Commission* (SEC). Composite summaries of the proved reserves for both the total controlled interests and the net profits interests are presented below.

Total Controlled Interests

		Proved Developed Producing	Proved Developed Non - Producing	Proved Developed	Proved Undeveloped	Total Proved
Net Reserves						
Oil	– Mbbl	5,594.5	6.3	5,600.8	575.2	6,176.0
Gas	– MMcf	13,374.1	12,840.0	26,214.1	1,846.4	28,060.5
Revenue						
Oil	– M$	359,276.0	449.8	359,725.7	32,811.4	392,537.2
Gas	– M$	20,273.0	25,573.6	45,846.6	2,689.8	48,536.4
Net Taxes	– M$	31,332.2	1,405.3	32,737.4	2,826.5	35,564.0
Operating Expenses	– M$	158,517.7	2,418.3	160,936.0	3,082.5	164,018.5
Investments	– M$	0.0	4,844.1	4,844.1	14,782.9	19,627.0
Net Operating Income (BFIT)	– M$	189,699.1	17,355.7	207,054.8	14,809.3	221,864.1
Discounted at 10%	**– M$**	**96,026.8**	**10,366.8**	**106,393.6**	**3,096.0**	**109,489.6**

Net Profits Interests

		Proved Developed Producing	Proved Developed Non - Producing	Proved Developed	Proved Undeveloped	Total Proved
Net Reserves						
Oil	–Mbbl	2,437.0	4.0	2,441.0	298.0	2,739.0
Gas	–MMcf	5,892.0	7,290.0	13,182.0	962.0	14,144.0
Revenue						
Oil	–M$	156,438.0	270.0	156,708.0	16,086.0	172,794.0
Gas	–M$	8,963.0	14,508.0	23,471.0	1,405.0	24,876.0
Net Taxes	–M$	13,644.0	894.0	14,538.0	1,407.0	15,945.0
Operating Expenses	–M$	0.0	0.0	0.0	0.0	0.0
Investments	–M$	0.0	0.0	0.0	0.0	0.0
Net Operating Income (BFIT)	–M$	151,759.0	13,886.0	165,645.0	16,079.0	181,724.0
Discounted at 10%	**–M$**	**76,822.0**	**8,293.0**	**85,115.0**	**6,246.0**	**91,362.0**

Future revenue is prior to deducting state production taxes and ad valorem taxes. Future net cash flow is after deducting these taxes, future capital costs and operating expenses, but before consideration of federal income taxes. In accordance with SEC guidelines, the future net cash flow has been discounted at an annual rate of ten percent to determine its "present worth". The present worth is shown to indicate the effect of time on the value of money and should not be construed as being the fair market value of the properties.

The oil reserves include oil, condensate, and NGL. Oil volumes are expressed in barrels (42 U.S. gallons). Gas volumes are expressed in thousands of standard cubic feet (Mcf) at contract temperature and pressure base.

Our estimates are for proved reserves only and do not include any probable or possible reserves nor have any values been attributed to interest in acreage beyond the location for which undeveloped reserves have been estimated.

Presentation

This report is divided into Total Controlled Interests sections and 80% Net Profits Interest sections, each with five reserve category sections: total Proved ("TP"), Proved Developed ("PF"), Proved Developed Producing ("PDP"), Proved Developed Non-Producing ("PDNP"), and Proved Undeveloped ("PUD") reserves. Within the PDP, PDNP, and PUD sections, there are Table I and Table II summaries. The Table I presents composite reserve estimates and economic forecasts for the particular reserve category. Following Table I is a Table II "oneline" summary that present estimates of ultimate recovery, gross and net reserves, ownership, revenue, expenses, investments, net income and discounted cash flow for the individual properties that make up the corresponding Table I.

For a more detailed explanation of the report layout, please refer to the Table of Contents following this letter. The data presented in the composite Tables I are explained in page one (1) of the Appendix.

Net Profit Calculation

The net profits interests entitle the Trust to receive 80% of the net proceeds attributable to the Company interest from the sale of production from the underlying properties.

Hydrocarbon Pricing

The base SEC oil and gas prices calculated for December 31, 2023 were $75.48/bbl and $2.130/MMBTU, respectively. As specified by the SEC, a company must use a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. The base oil price is based upon WTI-Cushing spot prices (EIA) during 2024 and the base gas price is based upon Henry Hub spot prices (EIA) during 2024.

The base prices were adjusted for differentials on a per-property basis, which may include local basis differentials, transportation, gas shrinkage, gas heating value (BTU content) and/or crude quality and gravity corrections. After these adjustments, the net realized prices for the SEC price case over the life of the proved properties was estimated to be $63.58 per barrel for oil and $1.73 per MCF for gas. All economic factors were held constant in accordance with SEC guidelines.

Economic Parameters

Ownership was accepted as furnished and has not been independently confirmed. Oil and gas price differentials, lease operating expenses (LOE), workover expenses, overhead expenses and investments were calculated and prepared by Company and were thoroughly reviewed by us for accuracy and completeness. LOE was determined at the well level using averages determined from historical lease operating statements. All economic parameters, including expenses and investments, were held constant (not escalated) throughout the life of these properties.

Severance tax rates were applied at normal state percentages of oil and gas revenue. Ad valorem taxes were applied to each property as provided by your office.

Possible Effects of Federal and State Legislation

Federal, state and local laws and regulations, which are currently in effect and that govern the development and production of oil and natural gas, have been considered in the evaluation of proved reserves for this report. However, the impact of possible changes to legislation or regulations to future operating expenses and investment costs have not been included in the evaluation. These possible changes could have an effect on the reserves and economics. However, we do not anticipate nor are we aware of any legislative changes or restrictive regulatory actions that may impact the recovery of reserves.

SEC Conformance and Regulations

The reserve classifications and the economic considerations used herein for the SEC pricing scenario conform to the criteria of the SEC as defined in pages 3 and 4 of the Appendix. The reserves and economics are predicated on regulatory agency classifications, rules, policies, laws, taxes and royalties currently in effect except as noted herein. The possible effects of changes in legislation or other Federal or State restrictive actions which could affect the reserves and economics have not been considered. However, we do not anticipate nor are we aware of any legislative changes or restrictive regulatory actions that may impact the recovery of reserves.

Reserve Estimation Methods

The methods employed in estimating reserves are described in page 2 of the Appendix. Reserves for proved developed producing wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to similar production, both of which are considered to provide a relatively high degree of accuracy.

Non-producing reserve estimates, for both developed and undeveloped properties, were forecast using either volumetric or analogy methods, or a combination of both. These methods provide a relatively high degree of accuracy for predicting proved developed non-producing and proved undeveloped reserves for the Company properties, due to the mature nature of their properties targeted for development and an abundance of subsurface control data. The assumptions, data, methods and procedures used herein are appropriate for the purpose served by this report.

General Discussion

The estimates and forecasts were based upon interpretations of data furnished by your office and available from our files. To some extent information from public records has been used to check and/or supplement these data. The basic engineering and geological data were subject to third party reservations and qualifications. Nothing has come to our attention, however, that would cause us to believe that we are not justified in relying on such data. All estimates represent our best judgment based on the data available at the time of preparation. Due to inherent uncertainties in future production rates, commodity prices and geologic conditions, it should be realized that the reserve estimates, the reserves actually recovered, the revenue derived therefrom and the actual cost incurred could be more or less than the estimated amounts.

An on-site field inspection of the properties has not been performed. The mechanical operation or condition of the wells and their related facilities have not been examined nor have the wells been tested by Cawley, Gillespie & Associates, Inc. Possible environmental liability related to the properties has not been investigated nor considered. The cost of plugging and the salvage value of equipment at abandonment have not been included as part of the workover expenses described previously.

Closing

Cawley, Gillespie & Associates, Inc. is a Texas Registered Engineering Firm (F-693), made up of independent registered professional engineers and geologists that have provided petroleum consulting services to the oil and gas industry for over 50 years. This evaluation was supervised by W. Todd Brooker, Senior Vice President at Cawley, Gillespie & Associates, Inc. and a State of Texas Licensed Professional Engineer (License #83462). We do not own an interest in the properties or Permianville Resource Partners LLC or Permianville Royalty Trust and are not employed on a contingent basis. We have used all methods and procedures that we consider necessary under the circumstances to prepare this report. Our work-papers and related data utilized in the preparation of these estimates are available in our office. We consent to the filing of this report as an exhibit to the Annual Report on Form 10-K of Permianville Royalty Trust for the year-end December 31, 2024.

Yours very truly,

W. Todd Brooker, P.E.
Senior Vice President
CAWLEY, GILLESPIE & ASSOCIATES, INC.
Texas Registered Engineering Firm (F-693)

APPENDIX

Methods Employed in the Estimation of Reserves

The four methods customarily employed in the estimation of reserves are (1) *production performance*, (2) *material balance*, (3) *volumetric* and (4) *analogy*. Most estimates, although based primarily on one method, utilize other methods depending on the nature and extent of the data available and the characteristics of the reservoirs.

Basic information includes production, pressure, geological and laboratory data. However, a large variation exists in the quality, quantity and types of information available on individual properties. Operators are generally required by regulatory authorities to file monthly production reports and may be required to measure and report periodically such data as well pressures, gas-oil ratios, well tests, etc. As a general rule, an operator has complete discretion in obtaining and/or making available geological and engineering data. The resulting lack of uniformity in data renders impossible the application of identical methods to all properties, and may result in significant differences in the accuracy and reliability of estimates.

A brief discussion of each method, its basis, data requirements, applicability and generalization as to its relative degree of accuracy follows:

Production performance. This method employs graphical analyses of production data on the premise that all factors which have controlled the performance to date will continue to control and that historical trends can be extrapolated to predict future performance. The only information required is production history. Capacity production can usually be analyzed from graphs of rates versus time or cumulative production. This procedure is referred to as “decline curve” analysis. Both capacity and restricted production can, in some cases, be analyzed from graphs of producing rate relationships of the various production components. Reserve estimates obtained by this method are generally considered to have a relatively high degree of accuracy with the degree of accuracy increasing as production history accumulates.

Material balance. This method employs the analysis of the relationship of production and pressure performance on the premise that the reservoir volume and its initial hydrocarbon content are fixed and that this initial hydrocarbon volume and recoveries therefrom can be estimated by analyzing changes in pressure with respect to production relationships. This method requires reliable pressure and temperature data, production data, fluid analyses and knowledge of the nature of the reservoir. The material balance method is applicable to all reservoirs, but the time and expense required for its use is dependent on the nature of the reservoir and its fluids. Reserves for depletion type reservoirs can be estimated from graphs of pressures corrected for compressibility versus cumulative production, requiring only data that are usually available. Estimates for other reservoir types require extensive data and involve complex calculations most suited to computer models which makes this method generally applicable only to reservoirs where there is economic justification for its use. Reserve estimates obtained by this method are generally considered to have a degree of accuracy that is directly related to the complexity of the reservoir and the quality and quantity of data available.

Volumetric. This method employs analyses of physical measurements of rock and fluid properties to calculate the volume of hydrocarbons in-place. The data required are well information sufficient to determine reservoir subsurface datum, thickness, storage volume, fluid content and location. The volumetric method is most applicable to reservoirs which are not susceptible to analysis by production performance or material balance methods. These are most commonly newly developed and/or no-pressure depleting reservoirs. The amount of hydrocarbons in-place that can be recovered is not an integral part of the volumetric calculations but is an estimate inferred by other methods and a knowledge of the nature of the reservoir. Reserve estimates obtained by this method are generally considered to have a low degree of accuracy; but the degree of accuracy can be relatively high where rock quality and subsurface control is good and the nature of the reservoir is uncomplicated.

Analogy. This method which employs experience and judgment to estimate reserves, is based on observations of similar situations and includes consideration of theoretical performance. The analogy method is a common approach used for “resource plays,” where an abundance of wells with similar production profiles facilitates the reliable estimation of future reserves with a relatively high degree of accuracy. The analogy method is applicable where the data are insufficient or so inconclusive that reliable reserve estimates cannot be made by other methods. Reserve estimates obtained by this method are generally considered to have a relatively low degree of accuracy.

Much of the information used in the estimation of reserves is itself arrived at by the use of estimates. These estimates are subject to continuing change as additional information becomes available. Reserve estimates which presently appear to be correct may be found to contain substantial errors as time passes and new information is obtained about well and reservoir performance.

The Securities and Exchange Commission, in SX Reg. 210.4-10 dated November 18, 1981, as amended on September 19, 1989 and January 1, 2010, requires adherence to the following definitions of oil and gas reserves:

"(22) **Proved oil and gas reserves**. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations— prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Instruction 4 of Item 2(b) of Securities and Exchange Commission Regulation S-K was revised January 1, 2010 to state that "a registrant engaged in oil and gas producing activities shall provide the information required by Subpart 1200 of Regulation S–K." This is relevant in that Instruction 2 to paragraph (a)(2) states: "The registrant is *permitted, but not required*, to disclose probable or possible reserves pursuant to paragraphs (a)(2)(iv) through (a)(2)(vii) of this Item."

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

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