SAN JUAN BASIN ROYALTY TRUST
Form 10-K
February 29, 2016
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

x **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the Fiscal Year Ended December 31, 2015

or

¨ **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the transition period from to

Commission File No. 001-08032

San Juan Basin Royalty Trust

(Exact name of registrant as specified in the Amended and Restated San Juan Basin Royalty Trust Indenture)

Texas *(State or other jurisdiction of* *incorporation or organization)*	**75-6279898** *(I.R.S. Employer Identification No.)*
Compass Bank **300 W. 7th Street, Suite B** **Fort Worth, Texas** *(Address of principal executive offices)*	**76102** *(Zip Code)*

(866) 809-4553

(Registrant s telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Units of Beneficial Interest	New York Stock Exchange

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

None

(Title of Class)

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

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 x

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 x No ¨

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

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

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

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

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

Aggregate market value of the Units of Beneficial Interest held by non-affiliates of the registrant as of June 30, 2015: $500,282,990.

At February 29, 2016 there were 46,608,796 Units of Beneficial Interest of the registrant outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None.

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Information Regarding Forward-Looking Statements

Certain information included in this Annual Report on Form 10-K contains, and other materials filed or to be filed by the San Juan Basin Royalty Trust (the Trust) with the Securities and Exchange Commission (the SEC) (as well as information included in oral statements or other written statements made or to be made by the Trust) may contain or include, forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act) and Section 27A of the Securities Act of 1933, as amended (the Securities Act). Such forward-looking statements may be or may concern, among other things, capital expenditures, drilling activity, development activities, production efforts and volumes, hydrocarbon prices, estimated future net revenues, estimates of reserves, the results of the Trust s activities, and regulatory matters. Such forward-looking statements generally are accompanied by words such as may, will, estimate, expect, predict, project, anticipate, goal, should, assume, believe, plan, intend, or other words that convey the uncertainty of future event Such statements are based on certain assumptions of Compass Bank, the Trustee (the Trustee) and by Burlington Resources Oil & Gas Company LP (Burlington), the owner of the working interest, with respect to future events; are based on an assessment of, and are subject to, a variety of factors deemed relevant by the Trustee and Burlington; and involve risks and uncertainties. However, whether actual results and developments will conform with such expectations and predictions is subject to a number of risks and uncertainties, including the risk factors discussed in Item 1A of Part I of this Annual Report, which could affect the future results of the energy industry in general, and the Trust and Burlington in particular, and could cause those results to differ materially from those expressed in such forward-looking statements. The actual results or developments anticipated may not be realized or, even if substantially realized, they may not have the expected consequences to or effects on Burlington s business and the Trust. Such statements are not guarantees of future performance and actual results or developments may differ materially from those projected in such forward-looking statements. The Trust undertakes no obligation to publicly update or revise any forward-looking statements, except as required by applicable law.

Burlington Information

As a holder of a net overriding royalty interest, the Trust relies on Burlington for information regarding Burlington itself; ConocoPhillips and its other affiliates; the Underlying Properties (as defined below), including the operations, acreage, well count, production volumes, sales revenues, capital expenditures, operating expenses, reserves, drilling plans, drilling results and leasehold terms related to the Underlying Properties; and factors and circumstances that have or may affect the foregoing. See Part II, Item 9A Controls and Procedures.

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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following are definitions adopted by the SEC and the Financial Accounting Standards Board which are applicable to terms used within this Annual Report on Form 10-K:

Bbl: Barrel, generally 42 U.S. gallons measured at 60 degrees Fahrenheit.

Bbls/d: Barrels per day.

Bcf: Billion cubic feet.

Btu: British thermal unit; the amount of heat necessary to raise the temperature of one pound of water one degree Fahrenheit.

Coal Seam Well: A well completed to a coal deposit found to contain and emit natural gas.

Conventional Well: A well completed to a formation historically found to contain deposits of oil or natural gas (for example, in the San Juan Basin, the Pictured Cliffs, Dakota and Mesaverde formations) and operated in the conventional manner.

Developed oil and natural gas reserves: 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. See 17 CFR 210.4-10(a)(6).

Distributable Income: An amount paid to Unit Holders equal to the Royalty Income received by the Trustee during a given period plus interest, less the expenses and payment of liabilities of the Trust, adjusted by any changes in cash reserves.

Estimated future net revenues: Computed by applying current oil and natural gas prices (with consideration of price changes only to the extent provided by contractual arrangements and allowed by federal regulation) to estimated future production of proved oil and natural gas reserves as of the date of the latest balance sheet presented, less estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves and assuming continuation of existing economic conditions. See 17 CFR 210.4-10(c)(4)(A). Estimated future net revenues are sometimes referred to in this Annual Report on Form 10-K as estimated future net cash flows.

GAAP: United States generally accepted accounting principles.

Grantor Trust: A trust (or portion thereof) with respect to which the grantor or an assignee of the grantor, rather than the trust, is treated as the owner of the trust properties and is taxed directly on the trust income for Federal income tax purposes under Sections 671 through 679 of the Internal Revenue Code of 1986, as amended.

Henry Hub: Henry Hub index.

Horizontal Well: A well that begins as a vertical or inclined linear bore, which extends from the surface to a subsurface location just above the target oil or natural gas reservoir, then bears off to intersect the reservoir and, thereafter, continues at a near-horizontal attitude to substantially or entirely remain within the reservoir until the desired bottom hole location is reached.

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Indenture: The Amended and Restated Royalty Trust Indenture, dated December 12, 2007 (the original Royalty Trust Indenture, dated November 1, 1980 having been entered into between Southland Royalty Company and The Fort Worth National Bank, as Trustee, and previously amended and restated effective September 30, 2002).

Infill Drilling: The drilling of wells intended to be completed to proven reservoirs or formations, sometimes occurring in conjunction with regulatory approval for increased density in the spacing of wells.

Lease Operating Expenses: Expenses incurred in the operation of a producing property as apportioned among the several parties in interest.

Mcf: Thousand cubic feet.

Mcf/d: Thousand cubic feet per day.

MMBtu: Million British thermal units.

MMcf: Million cubic feet.

Multiple Completion Well: A well which produces simultaneously, with or without separate tubing strings, from two or more producing horizons or alternatively from each.

Net Overriding Royalty Interest: A share of gross production from a property, measured by net profits from operation of the property and carved out of the working interest, i.e., a net profits interest.

Natural Gas Liquids (NGL): Those hydrocarbons that are separated from the gas as liquids through the process of absorption, condensation, adsorption or other methods in gas processing or cycling plants.

Present value of estimated future net revenues: Computed using the estimated future net revenues (as defined above) and a discount rate of 10%. See 17 CFR 210.4-10(c)(4)(A).

Proved developed reserves: Proved natural gas and oil reserves that can be expected to be recovered 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.

Proved natural gas and oil reserves: Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government 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. See 17 CFR 210.4-10(a)(22).

Proved undeveloped reserves (PUDs): 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. 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. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are schedule to be drilled within five years, unless specific circumstances justify a longer time. Under no circumstances shall estimates for proved 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, or by other evidence using reliable technology establishing reasonable certainty.

Reasonable certainty: (i) If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered or (ii) if probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease. See 17 CFR 210.4-10(a)(24).

Reserves: Estimated remaining quantities of oil and natural 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 natural gas or related substances to market, and all permits and financing required to implement the project. See 17 CFR 210.4-10(a)(26).

Royalty: The principal asset of the Trust; the 75% net overriding royalty interest conveyed to the Trust on November 3, 1980, by Southland Royalty Company, the predecessor to Burlington, which was carved out of the Underlying Properties.

Royalty Income: The net proceeds attributable to the Royalty.

Underlying Properties: The working, royalty and other oil and natural gas interests owned by Southland Royalty Company, the predecessor to Burlington, in properties located in the San Juan Basin of northwestern New Mexico, out of which the Royalty was carved.

Undeveloped oil and natural gas reserves: 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. See 17 CFR 210.4-10(a)(31).

Units: The units of ownership of the Trust, comprised of undivided fractional interests in the beneficial interest of the Trust, equal to the number of shares of common stock of Southland Royalty Company outstanding at the close of business on November 3, 1980.

Working Interest: The operating interest under an oil and natural gas lease.

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PART I

ITEM 1. *BUSINESS*

The Trust is an express trust created under the laws of the state of Texas by the San Juan Basin Royalty Trust Indenture entered into on November 1, 1980, between Southland Royalty Company (Southland) and The Fort Worth National Bank. Effective as of September 30, 2002, the original indenture was amended and restated and, effective as of December 12, 2007, the restated indenture was amended and restated, which we refer to as the Indenture. As a result of a series of mergers and other transactions, the current Trustee of the Trust is Compass Bank (the Trustee), which is a wholly-owned subsidiary of Banco Bilbao Vizcaya Argentaria, S.A.

The Conveyance and the Royalty

Pursuant to the Net Overriding Royalty Conveyance (the Conveyance) effective November 1, 1980, Southland conveyed to the Trust a 75% net overriding royalty interest (the Royalty) that burdens certain of Southland s oil and natural gas interests (the Underlying Properties) in properties located in the San Juan Basin of northwestern New Mexico. Subsequent to the Conveyance of the Royalty, through a series of assignments and mergers, Southland s successor became Burlington Resources Oil & Gas Company LP (Burlington). Burlington is an indirect wholly-owned subsidiary of ConocoPhillips.

The Royalty functions generally as a net profits interest. Under the terms of the Conveyance, the Trust receives 75% of net proceeds from the Underlying Properties. The term net proceeds, as used in the Conveyance, means the excess of gross proceeds received by Burlington during a particular period over production costs for such period. Gross proceeds means the amount received by Burlington (or any subsequent owner of the Underlying Properties) from the sale of the production attributable to the Underlying Properties, subject to certain adjustments. Production costs generally means costs incurred on an accrual basis by Burlington in operating the Underlying Properties, including both capital and non-capital costs. For example, these costs include development drilling, production and processing costs, applicable taxes and operating charges. If production costs exceed gross proceeds in any month, the excess is recovered out of future gross proceeds prior to the making of further payment to the Trust, but the Trust is not otherwise liable for any production costs or other costs or liabilities attributable to the Underlying Properties or the minerals produced therefrom. If at any time the Trust receives more than the amount due under the Royalty, it is not obligated to return such overpayment, but the amounts payable to it for any subsequent period are reduced by such amount, plus interest, at a rate specified in the Conveyance.

The Royalty constitutes the principal asset of the Trust. The beneficial interest in the Royalty is divided into 46,608,796 units (the Units) representing undivided fractional interests in the beneficial interest of the Trust equal to the number of shares of the common stock of Southland outstanding as of the close of business on November 3, 1980. Each stockholder of Southland of record at the close of business on November 3, 1980 received one freely tradable Unit for each share of the common stock of Southland then held. Holders of Units are referred to herein as Unit Holders.

As of December 31, 2015, 96% of the Trust s estimated proved reserves consisted of natural gas reserves, and 96% of the gross proceeds from the Underlying Properties in 2015 were attributable to the production and sale by Burlington of natural gas. Accordingly, the market price for natural gas produced and sold from the San Juan Basin heavily influences the amount of Trust income available for distribution to the Unit Holders by the Trust and, by extension, the price of the Units. Normally there is greater demand for natural gas used for heating or air conditioning purposes in the summer and winter months than during the rest of the year.

The Trustee

The primary function of the Trustee is to collect the net proceeds attributable to the Royalty (Royalty Income), to pay all expenses and charges of the Trust and to distribute the remaining available income to the Unit Holders. The Trust received approximately $19.4 million, $61.5 million and $38.0 million in Royalty

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Income from Burlington in each of the fiscal years ended December 31, 2015, 2014 and 2013, respectively. After deducting administrative expenses and accounting for interest income and any change in cash reserves, the Trust distributed approximately $17.0 million, $59.9 million, and $36.5 million to Unit Holders in each of the fiscal years ended December 31, 2015, 2014 and 2013, respectively. The Trust s corpus was approximately $8.7 million, $9.4 million, and $11.0 million as of December 31, 2015, 2014 and 2013, respectively.

Proceeds from production in the first month are generally received by Burlington in the second month, the net proceeds attributable to the Royalty are paid by Burlington to the Trustee in the third month, and distribution by the Trustee to the Unit Holders is made in the fourth month. Unit Holders of record as of the last business day of each month (the monthly record date) will be entitled to receive the calculated monthly distribution amount for such month on or before ten business days after the monthly record date. The amount of each monthly distribution will generally be determined and announced ten days before the monthly record date. The aggregate monthly distribution amount is the excess of (i) the net proceeds attributable to the Royalty paid to the Trustee, plus any decrease in cash reserves previously established for liabilities and contingencies of the Trust, over (ii) the expenses and payments of liabilities of the Trust, plus any net increase in cash reserves.

The Trustee may, in its sole discretion, establish a cash reserve for payment of Trust liabilities that are contingent or uncertain or otherwise not currently due and payable. As of December 31, 2015 and 2014, the Trustee had established cash reserves of $0.5 million and $0.2 million, respectively. Because a prolonged decline in natural gas prices may reduce Royalty Income, the Trustee has increased the amount of cash reserves during 2016 by $150,000 as of February 29, 2016 and expects to further increase the total amount of cash reserves to approximately $1.0 million during the year.

Cash being held by the Trustee as cash reserves or pending distribution may be placed, in the Trustee s discretion, in obligations issued by (or unconditionally guaranteed by) the United States or any agency thereof, repurchase agreements secured by obligations issued by the United States or any agency thereof, certificates of deposit of banks having capital, surplus and undivided profits in excess of $50 million or money market funds that have been rated at least AAm by Standard & Poor s and at least Aa by Moody s, subject, in each case, to certain other qualifying conditions. Currently, such funds are placed in interest-bearing negotiable order of withdrawal accounts whose funds are either insured by the Federal Deposit Insurance Corporation or secured by other assets of BBVA Compass Bank.

The other powers and duties of the Trustee are set forth in the Indenture and include the prosecution and defense of claims by and against the Trust, the engagement of consultants and professionals and the payment of Trust liabilities. If the Trustee determines that the Trust does not have sufficient funds to pay its liabilities, the Trustee may borrow funds on behalf of the Trust, in which case no distributions will be made to Unit Holders until such borrowings are repaid in full. The Trustee may not sell or dispose of any part of the assets of the trust without the affirmative vote the Unit Holders of 75% of all of the Units outstanding; however, the Trustee may sell up to 1% of the value of the Royalty (as determined pursuant to the Indenture) during any 12-month period without the consent of the Unit Holders if it determines such a sale is in the best interest of the Unit Holders. The Trust does not operate the Underlying Properties and is not empowered to carry on any business activity. The Trust has no employees, officers or directors. All administrative functions of the Trust are performed by the Trustee.

Under the Indenture, the Trustee may act in its discretion in carrying out its powers and performing its duties and is liable only for fraud or for acts and omissions in bad faith. The Trustee is not liable for any act or omission of its agents or employees unless the Trustee acted in bad faith in its selection and retention of such agents or employees. The Indenture provides that the Trustee and its officers, agents and employees must be indemnified and receive reimbursement of expenses from the assets of the Trust for liabilities and claims incurred in the administration of the Trust, except for liabilities and claims arising from the Trustee s fraud or bad faith.

Duration of the Trust

The Trust will terminate if (a) its gross revenue for each of two successive years is less than $1 million per year or, if earlier, (b) the Unit Holders of at least 75% of all of the Units outstanding vote in favor of termination. Upon termination of the Trust, the Trustee must sell the Royalty and distribute the proceeds to Unit Holders after satisfying or establishing reserves to satisfy the liabilities of the Trust.

Burlington

Burlington and other affiliates of ConocoPhillips are the principal operators of the majority of the Underlying Properties. As an operator, Burlington has the obligation under the Conveyance to conduct its operations in accordance with reasonable and prudent business judgment and good oil and natural gas field practices. Burlington has the right to abandon any well when, in its opinion, such well ceases to produce or is not capable of producing oil and natural gas in paying quantities. Burlington reserves the right to not participate in operations on the Underlying Properties when it has a right to do so under the applicable operating or similar agreement. Burlington also is responsible, subject to the terms of an agreement with the Trust, for marketing the production from such properties, either under existing sales contracts or under future arrangements, at the best prices and on the best terms it shall deem reasonably obtainable in the circumstances. Additionally, Burlington is obligated under the Conveyance to maintain books and records sufficient to determine the amounts payable to the Trustee.

Additional Information

The principal office of the Trust is located at 300 West 7th Street, Suite B, Fort Worth, Texas 76102 (toll-free telephone number (866) 809-4553). The Trust makes available (free of charge) its annual, quarterly and current reports (and any amendments thereto) filed with the SEC through its website at *www.sjbrt.com* as soon as reasonably practicable after electronically filing or furnishing such material with or to the SEC. The Trust s materials filed with the SEC are also available at the SEC s Public Reference Room at 100 F Street, NE, Washington, DC 20549 or by calling the Public Reference Room of the SEC at 1-800-SEC-0330. The SEC also maintains the internet site of *www.sec.gov*. This site contains reports and, as applicable, proxy and information statements, and other information regarding the Trust and other issuers that file electronically with the SEC.

The Trust is a widely held fixed investment trust (WHFIT) classified as a non-mortgage widely held fixed investment trust (NMWHFIT) for federal income tax purposes. The Trustee, 300 West 7th Street, Suite B, Fort Worth, Texas 76102 (toll-free telephone number (866) 809-4553, email address: *sjt.us@bbva.com*), is the representative of the Trust that will provide tax information in accordance with the applicable U.S. Treasury Regulations governing the information reporting requirements of the Trust as a WHFIT and a NMWHFIT. The tax information is generally posted by the Trustee on the Trust s website: *www.sjbrt.com*.

ITEM 1A. ***RISK FACTORS***

Described below are certain risks that we believe are associated with an investment in the Units of the Trust and the oil and natural gas industry. There may be additional risks that are not presently material or known. You should carefully consider each of the following risks and all other information set forth in this Annual Report on Form 10-K. If any of the events described below occur, our financial condition could be materially adversely affected.

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Oil and natural gas prices fluctuate due to a number of factors, and lower prices will reduce net proceeds to the Trust and distributions to Unit Holders.

The Trust s monthly distributions are highly dependent upon the prices realized from the sale of natural gas and, to a lesser extent, oil. Oil and natural gas prices can fluctuate widely in response to a variety of factors that are beyond the control of the Trust and Burlington. Factors that contribute to price fluctuation include, among others:

- political conditions worldwide, in particular political disruption, war or other armed conflicts in oil producing regions;
- worldwide economic conditions;
- weather conditions;
- the supply and price of foreign oil and natural gas, including liquefied natural gas;
- the level of consumer demand;
- the price and availability of alternative fuels;
- the proximity to, and capacity of, transportation facilities;
- the effect of worldwide energy conservation and climate change measures; and
- technological advances in the methods for the exploration and production of natural gas.

Moreover, government regulations, such as regulation of natural gas transportation and price controls, can affect product prices in the long term. 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. Oil and natural gas prices declined significantly in the second half of 2014 and during 2015 and have remained low compared to prices in the first half of 2014. In addition, the market price of oil and natural gas is generally higher in the winter months than during other months of the year due to increased demand for oil and natural gas for heating purposes during the winter season. During 2015, the price of natural gas and oil for production from the Underlying Properties declined significantly from an average price for natural gas of $4.47 per Mcf in 2014 to $2.60 per Mcf in 2015, and the price for oil declined from an average price of $82.99 per Bbl in 2014 to $47.00 per Bbl in 2015. As a result of the price decline, certain wells have become less economical and, as a result, Burlington has reduced production from the Underlying Properties. Natural gas production from the Underlying Properties decreased from 30,872,147 Mcf in 2014 to 29,128,439 Mcf in 2015. See Item 7. Trustee s Discussion and Analysis of Financial Condition and Results of Operations.

Lower oil and natural gas prices will reduce proceeds to which the Trust is entitled and may ultimately reduce the amount of oil and natural gas that is economic to produce from the Underlying Properties. As a result, Burlington or any third-party operator of any of the Underlying Properties could determine during periods of low oil and natural gas prices to shut in or curtail production from wells on the Underlying Properties. In addition, the operator of the Underlying Properties could determine during periods of low oil and natural gas prices to 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, Burlington or any third-party operator may abandon any well or property if it reasonably believes that the well or property can no longer produce oil and natural gas in commercially economic quantities. This could result in termination of the portion of the royalty interests relating to the abandoned well or property, and Burlington would have no obligation to drill a replacement well.

Burlington has informed us that it has not and does not intend to enter into derivative contracts or other hedging contracts with respect to the sale of production from the Underlying Properties. Absent such arrangements, the revenue received from such production will be subject to market prices.

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Increased costs of production and development will result in decreased Trust distributions.

Production and development costs attributable to the Underlying Properties are deducted in the calculation of net proceeds. Accordingly, higher production and development costs, without concurrent increases in revenues, decrease the share of net proceeds paid to the Trust as Royalty Income.

If development and production costs of the Underlying Properties exceed the proceeds of production from the Underlying Properties, such excess costs are carried forward and the Trust will not receive a share of net proceeds for the Underlying Properties until future net proceeds from production from such properties exceed the total of the excess costs. Development activities may not generate sufficient additional revenue to repay the costs; however, the Trust is not obligated to repay the excess costs except through future production.

Trust reserve estimates depend on many assumptions that may prove to be inaccurate, which could cause both estimated reserves and estimated future revenues to be too high.

The value of the Units of the Trust depends upon, among other things, the amount of reserves attributable to the Royalty and the estimated future value of the reserves. Estimating reserves is inherently uncertain. Ultimately, actual production, revenues and expenditures for the Underlying Properties will vary from estimates and those variations could be material. Petroleum engineers consider many factors and make assumptions in estimating reserves. Those factors and assumptions may include:

- historical production from the area compared with production rates from similar producing areas;
- the assumed effect of governmental regulation; and
- assumptions about future commodity price adjustments, production and development costs, severance and excise taxes, and capital expenditures.

Changes in these assumptions may materially change reserve estimates. Our estimate of proved natural gas reserves declined from 120.7 Bcf to 75.6 Bcf, as of December 31, 2014 and 2015, respectively, a decrease of approximately 45.1 Bcf, or 37%. In addition, the discounted future net cash flows related to future Royalty Income from our proved reserves declined from $308.1 million to $103.1 million, as of December 31, 2014 and 2015, respectively, a decrease of approximately $205.0 million, or 67%. Such decreases are a result of lower natural gas and oil prices, and if natural gas and oil prices persist or decrease further, the value of our estimated proved reserves and future Royalty Income may decrease substantially. For more information regarding our proved reserves, see Item 2. Properties Oil and Natural Gas Reserves and Item 8. Financial Statements and Supplementary Data, Note 9.

The reserve data included herein are estimates only and are subject to many uncertainties. Actual quantities of oil and natural gas may differ considerably from the amounts set forth herein. In addition, different reserve engineers may make different estimates of reserve quantities and cash flows based upon the same available data.

The future financial condition of operators of the Underlying Properties could impede the operation of wells.

The value of the Royalty and the Trust s ultimate cash available for distribution is highly dependent on the financial condition of the operator of the wells. Neither Burlington nor any of the other operators of the Underlying Properties has agreed with the Trust to maintain a certain net worth or to be restricted by other similar covenants.

The ability to operate the Underlying Properties depends on all operators future financial condition and economic performance and access to capital, 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 such operators.

In the event of the bankruptcy of any operator of the Underlying Properties, the working interest owners in the affected properties, creditors or the debtor-in-possession would have to seek a new party to perform the operations of the affected wells. Burlington or the other working interest owners may not be able to find a replacement operator, and they may not be able to enter into a new agreement with such replacement party on favorable terms or within a reasonable period of time. As a result, such a bankruptcy may result in reduced production of reserves and decreased distributions to Unit Holders.

Production of oil and natural gas on the Underlying Properties could be materially and adversely affected by severe or unseasonable weather.

Production of oil and natural gas on the Underlying Properties could be materially and adversely affected by severe or unseasonable weather. Repercussions of severe weather conditions may include:

- evacuation of personnel and curtailment of operations
- weather-related damage to drilling rigs or other facilities, resulting in suspension of operations
- inability to deliver materials to worksites; and
- weather-related damage to pipelines and other transportation facilities.

Due to the Trust s lack of industry and geographic diversification, adverse developments in the Trust s existing area of operation could adversely impact its financial condition, results of operations and cash flows and reduce its ability to make distributions to the Unit Holders.

The Underlying Properties are operated for oil and natural gas production and are focused exclusively in the San Juan Basin. This concentration could disproportionately expose the Trust s interests to operational and regulatory risk in that area. Due to the lack of diversification in industry type and location of the Trust s interests, adverse developments in the oil and natural gas markets or the area of the Underlying Properties, including, for example, transportation or treatment capacity constraints, curtailment of production or treatment plant closures for scheduled maintenance, could have a significantly greater impact on the Trust s financial condition, results of operations and cash flows than if the Royalty were more diversified.

The operators of the Underlying Properties are subject to extensive governmental regulation that could affect the cost, manner and feasibility of conducting operations on the Underlying Properties, 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.

Oil and natural gas operations on the Underlying Properties are subject to laws and regulations adopted or promulgated by federal, state and local authorities. From time to time, those requirements may require Burlington and other operators of the Underlying Properties to incur substantial costs or restrict production. Changes in price controls, taxes and environmental laws relating to the crude oil and natural gas industry have the ability to significantly affect crude oil and natural gas production, operations and economics. We cannot always predict with certainty whether agencies or courts will change their interpretation of existing requirements, whether government authorities will adopt new requirements or the effect such changes may have on our business or financial condition.

Environmental laws, in particular, may change frequently and at times may force Burlington and other operators of the Underlying Properties to incur additional costs as those changes are implemented, or in instances of possible non-compliance, to incur penalties. Additionally, the discharge of natural gas, crude oil, or other pollutants into the air, soil or water may give rise to substantial liabilities to government agencies and third parties, and may require Burlington and other operators of the Underlying Properties to incur substantial costs of remediation.

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Some of the complex environmental requirements to which operation of the Underlying Properties may be subject include the Comprehensive Environmental Response, Compensation and Liability Act, the Resource Conservation and Recovery Act, the Oil Pollution Act of 1990, the Clean Air Act, the Clean Water Act, the Endangered Species Act, the Safe Drinking Water Act, the Occupational Safety and Health Act and analogous state statutes along with regulations developed under these laws. See Item 2. Properties Regulation.

Any new requirements under environmental or other statutes could increase the cost to operate the Underlying Properties, change the nature of such operations, delay operations or reduce the liquidity of, or otherwise negatively impact, the financial condition of Burlington and the other operators of the Underlying Properties. Such costs, delays and changes in operations could have a material adverse effect on the operation of the Underlying Properties, 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.

Operating risks for Burlington and other operators of the Underlying Properties can adversely affect Trust distributions.

Royalty Income payable to the Trust is derived from the sale of natural gas and oil production following the gathering and processing of those minerals, which operations are subject to risk inherent in such activities. Such risks include the following, which may result in production operations being curtailed, delayed or canceled:

- reductions in oil and natural gas prices;
- unusual or unexpected geological formations and miscalculations;
- equipment malfunctions, failures or accidents;
- lack of available gathering facilities or delays in construction of gathering facilities;
- lack of available capacity on interconnecting transmission pipelines;
- unexpected operational events;
- pipe or cement failures and casing collapses;
- pressures, fires, blowouts and explosions;
- uncontrollable flows of oil, natural gas, brine, water or drilling fluids;
- natural disasters;
- environmental hazards, such as oil and natural gas leaks, pipeline ruptures and discharges of toxic gases or well fluids;

- adverse weather conditions, such as extreme cold, fires caused by extreme heat or lack of rain and severe storms or tornadoes; and

- market limitations for oil and natural gas.

If anticipated production is lower due to any of the factors above or for any other reason, or if Burlington incurs additional operational or production costs as a result of these or other factors, the amount of Trust distributions may be significantly reduced.

None of the Trustee, the Trust nor the Unit Holders control the operation or development of the Underlying Properties.

Neither the Trustee nor the Unit Holders can influence or control the operation or future development of the Underlying Properties. The Underlying Properties are owned by Burlington, which operates a majority of such properties and handles the calculation of the net proceeds attributable to the Royalty and the payment of Royalty Income to the Trust. The Underlying Properties that are not operated by Burlington are operated by other operators, some of which may be affiliated with Burlington. The development of the Underlying Properties is conducted pursuant to operating and similar agreements to which the Trust is not a party and under which the Trust has no control or other rights to determine the location, timing and other key aspects of development and maintenance that may materially impact results of operations.

The Royalty can be sold and the Trust can be terminated in certain circumstances.

The Trustee may sell or dispose of any part of the assets of the trust with the affirmative vote the Unit Holders of 75% of all of the Units outstanding, except that the Trustee may sell up to 1% of the value of the Royalty (as determined pursuant to the Indenture) during any 12-month period without the consent of the Unit Holders. The Trust does not operate the Underlying Properties and is not empowered to carry on any business activity. The Trust will be terminated and the Trustee must sell the Royalty if holders of at least 75% of the Units approve the sale or vote to terminate the Trust, or if the Trust s gross revenue for each of two successive years is less than $1million per year. Any net proceeds of a sale following termination of the Trust will be distributed to the Unit Holders after satisfying or establishing reserves to satisfy the liabilities of the Trust, and Unit Holders will receive no further distributions from the Trust. We cannot assure you that any sale of Trust assets will be on terms acceptable to all Unit Holders.

Mineral properties, such as the Underlying Properties, are depleting assets, and if Burlington or other operators of the Underlying Properties do not perform additional development projects, the assets may deplete faster than expected.

The Royalty Income payable to the Trust is derived from the sale of depleting assets. The reduction in proved reserve quantities is a common measure of depletion. Future maintenance and development projects on the Underlying Properties will affect the quantity of proved reserves. The timing and size of these projects will depend primarily on the market prices of natural gas. If Burlington does not implement additional maintenance and development projects, the future rate of production decline of proved reserves may be higher than the rate currently expected by the Trust. Burlington has no contractual obligation to the Trust to make capital expenditures on the Underlying Properties in the future. Furthermore, for properties on which Burlington is not designated as the operator, Burlington has no control over the timing or amount of capital expenditures. Burlington has a right to not participate in the capital expenditures on properties for which it is not the operator, in which case Burlington and the Trust will not receive the proceeds from the sale of the production resulting from such capital expenditures. The Trust is not permitted to acquire other oil and natural gas properties or royalty interests to replace the depleting assets and production attributable to the Trust.

Payment resulting from the Trust s audit exceptions to Burlington s calculation of Royalty Income may be significantly delayed, if payment is made at all.

Generally, each year the Trust completes an audit of Royalty Income for the previous fiscal year and provides notice to Burlington of audit exceptions during the second half of each year. Additional time is often required to resolve such audit exceptions, and in some cases, the audit exceptions have resulted in litigation lasting several years. Our audit of fiscal year 2015 Royalty Income may result in significant additional audit exceptions. Although we continue to seek resolution of these exceptions, we cannot provide any assurance as to whether they will be resolved in the Trust s favor and when they will be resolved. Audit exceptions may be resolved by court orders, settlement agreements between the parties and other methods that may not be favorable to the Trust and could result in a decrease in Royalty Income.

The amount of funds available for distribution to Unit Holders will be reduced by the amount of any cash reserves maintained by the Trustee in respect of anticipated future Trust expenses.

The Trustee is authorized to determine in its discretion the amount of cash reserves needed to pay liabilities and contingencies of the Trust. The amount of distributions to Unit Holders in a period is reduced by the amount of any increase in cash reserves for that period. During 2015, cash reserves of the Trust were increased by $0.3

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million, from $0.2 million as of December 31, 2014 to $0.5 million as of December 31, 2015. Because a prolonged decline in natural gas prices may reduce Royalty Income, the Trustee has increased the amount of cash reserves during 2016 by $150,000 as of February 29, 2016 and expects to further increase the total amount of cash reserves to approximately $1.0 million during the year, which will reduce the amount of cash available for distribution to Unit Holders.

Unit Holders have limited voting rights.

Voting rights as a Unit Holder are more limited than those of stockholders of most public corporations. For example, there is no requirement for annual meetings of Unit Holders or for an annual or other periodic re-election of the Trustee. Unlike corporations, which are generally governed by boards of directors elected by their equity holders, the Trust is administered by a corporate trustee in accordance with the Indenture and other organizational documents. The Trustee has extremely limited discretion in its administration of the Trust. If the Trustee does not take appropriate action to enforce provisions of the Conveyance, the recourse of the Unit Holders would likely be limited to bringing a lawsuit against the Trustee to compel the Trustee to take specified actions. Unit Holders probably would not be able to sue Burlington or any other operator of the Underlying Properties. The Indenture provides that the Trustee may only be removed and replaced by the holders of a majority of the outstanding Units, at a duly called meeting of Unit Holders. As a result, it may be difficult for public Unit Holders to remove or replace the Trustee without the cooperation of holders of a substantial percentage of the outstanding Units.

The limited liability of Unit Holders is uncertain.

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

Conflicts of interest could arise between Burlington and the Trust.

Burlington could have interests that conflict with the interests of the Trust and the Unit Holders. For example, Burlington s interests may conflict with those of the Trust and the Unit Holders in situations involving the development, maintenance, operation or abandonment of the Underlying Properties. Additionally, Burlington may abandon a well that is no longer producing in paying quantities even though such well is still generating revenue for the Unit Holders. Burlington may make decisions with respect to expenditures and decisions to allocate resources to projects in other areas that adversely affect the Underlying Properties, including reducing expenditures on these properties, 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.

Burlington may, without the consent or approval of the Unit Holders, sell all or any part of its retained interest in the Underlying Properties. Although Burlington must require any purchaser of its retained interest in the Underlying Properties to assume Burlington s obligations with respect to those properties, such sale may not be in the best interests of the Trust and the Unit Holders. Any purchaser may lack Burlington s experience in the Underlying Properties or its creditworthiness.

Burlington may not be adequately insured against operational hazards.

Burlington is not obligated to the Trust to maintain any particular types or amounts of insurance, and insurance may not be commercially available at adequate levels to cover its operational hazards at all times

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during the life of the Trust. If a well is damaged, Burlington would have no obligation to drill a replacement well or otherwise compensate the Trust for the loss. The Trust does not have insurance or indemnification to protect against losses or delays in receiving proceeds from such events.

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 U.S. generally accepted accounting principles, GAAP. Although this basis of accounting is permitted for royalty Trusts by the Securities and Exchange Commission, the financial statements of the Trust differ from GAAP financial statements because revenues are not accrued in the month of production; certain cash reserves may be established for liabilities and contingencies of the Trust which would not be accrued in financial statements prepared in accordance with GAAP; expenses are recorded when paid instead of when incurred; and amortization of the Royalty calculated on a unit-of-production basis is charged directly to trust corpus instead of as an expense.

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 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 Unit Holders.

If the Trust were not treated as a grantor trust for federal income tax purposes, the Trust may be properly classified as a partnership for such purposes. Although the Trust would not become subject to 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 Unit Holders, the Trust s tax compliance requirements would be more complex and costly to implement and maintain, and its distributions to Unit Holders could be reduced as a result.

The Trustee has not requested a ruling from the U.S. Internal Revenue Service (IRS) regarding the tax status of the Trust, and the Trustee does not intend to request such a ruling or cannot assure you that such a ruling would be granted if requested or that the IRS will not challenge these positions on audit.

Unit Holders should be aware of the possible state tax implications of owning Units and should consult with their tax advisors.

Certain U.S. federal income tax preferences currently available with respect to oil and natural gas production may be eliminated as a result of future legislation.

Recently introduced legislation include proposals that would, among other things, eliminate or reduce certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to the repeal of the percentage depletion allowance for oil and natural gas properties. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, could reduce the cash available for distribution to the Unit Holders or adversely affect the value of the Units.

Unit Holders 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.

Unit Holders 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, Unit Holders are required to pay any federal and applicable state income taxes and, in some cases, other state and local income taxes on their share of the Trust s

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taxable income even if they receive no cash distributions from the Trust. A Unit Holder may not receive cash distributions from the Trust equal to such Unit Holder 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 Units could be taxed as ordinary income.

If a Unit Holder sells Units, the Unit Holder will recognize a gain or loss equal to the difference between the amount realized and the Unit Holder s tax basis in those Units. A substantial portion of any gain recognized may be taxed as ordinary income due to potential recapture items, including depletion recapture. Potential investors should consult with their tax advisors prior to acquiring Units.

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 Units on the monthly record date, instead of on the basis of the date a particular Unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among the Unit Holders.

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

ITEM 1B. ***UNRESOLVED STAFF COMMENTS***

None.

ITEM 2. ***PROPERTIES***

The Royalty conveyed to the Trust was carved out of Southland s (now Burlington s) working interests and royalty interests in certain properties situated in the San Juan Basin in northwestern New Mexico. See Item 1. Business for information on the conveyance of the Royalty to the Trust. References below to gross wells and acres are to the interests of all persons owning interests therein, while references to net are to the interests of Burlington (from which the Royalty was carved) in such wells and acres.

Unless otherwise indicated, the following information in this Item 2 is based upon data and information furnished to the Trustee by Burlington.

The Underlying Properties

The Underlying Properties consist of working interests, royalty interests, overriding royalty interests and other contractual rights in 151,900 gross (119,000 net) producing acres in San Juan, Rio Arriba and Sandoval Counties of northwestern New Mexico and 3,598 gross (1,708.1 net) wells, calculated on a well bore basis and not including multiple completions as separate wells. Of those wells, 13 gross (4.4 net) are oil wells and the balance are natural gas wells. Burlington reports that approximately 1,092 gross (609.4 net) of the wells are multiple completion wells resulting in a total of 4,608 gross (2,187.6 net) completions. Burlington has informed the Trust that all of the subject acreage is held by production, and even though it has not been fully developed in every formation, Burlington has classified all of such acreage as developed. Production from conventional natural gas wells is primarily from the Pictured Cliffs, Mesaverde and Dakota formations, ranging in depth from 1,500 to 8,000 feet. Additional production is attributable to coal seam reserves in the Fruitland Coal formation and an exploratory horizontal well in the Mancos Shale formation, which was completed on lands burdened by the Royalty in 2012. While Burlington will continue to assess its program of horizontal drilling on the Underlying Properties, it has not drilled additional horizontal wells and expects no new horizontal drilling activity in the San Juan Basin in 2016.

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Coal seam natural gas constituted approximately 38% of our total natural gas production during 2015 and approximately 27% of our proved natural gas reserves as of December 31, 2015. The process of removing coal seam natural gas is often referred to as degasification or desorption. Millions of years ago, natural gas was generated in the process of coal formation and absorbed into the coal. Water later filled the natural fracture system. When the water is removed from the natural fracture system, reservoir pressure is lowered and the natural gas desorbs from the coal. The desorbed natural gas then flows through the fracture system and is produced at the well bore. The volume of formation water production typically declines with time and the natural gas production may increase for a period of time before starting to decline. Typically, the volumes of natural gas produced from a coal seam well decline more rapidly than those of conventional wells. In order to dispose of the formation water, surface facilities including pumping units are required. The price of coal seam natural gas is typically lower than the price of conventional natural gas. This is because the heating value of coal seam natural gas is much lower than that of conventional natural gas due to (a) ever increasing percentages of carbon dioxide in coal seam natural gas (carbon dioxide has no heating value), and (b) the absence of heavier hydrocarbons such as ethanes, propanes, and butanes, which are present in conventional natural gas. Furthermore, the production costs and processing fees for coal seam natural gas are typically higher than the processing fees for conventional natural gas due to the cost of extracting the carbon dioxide.

The Royalty conveyed to the Trust is limited to the base of the Dakota formation, which is currently the deepest significant producing formation under acreage affected by the Royalty. Rights to production, if any, from deeper formations are retained by Burlington.

2016 Capital Expenditure Budget

Burlington has informed the Trust that its budget for capital expenditures for the Underlying Properties in 2016 is estimated to be $4.8 million. Burlington reports that based on its actual capital requirements, the pace of regulatory approvals, the mix of projects and swings in the price of natural gas, the actual capital expenditures for 2016 are subject to change.

Burlington s announced 2016 capital plan for the Underlying Properties anticipates capital expenditures of $4.8 million, of which $3.4 million is allocated to 20 facilities projects and $1.4 million is allocated to 20 facilities projects attributable to the budgets for prior years. Primarily due to depressed pricing for natural gas, Burlington has not allocated any capital expenditures for 2016 to its drilling program in the San Juan Basin. However, Burlington reported that it continually monitors natural gas prices and plans to restart the program at some point in the future, dependent upon such natural gas prices. Existing wells will continue to be operated.

Oil and Natural Gas Production

Production of oil and natural gas and related average sales prices attributable to each of the Underlying Properties and the Royalty for the three years ended December 31, 2015, were as follows:

	For the year ended December 31,					
	2015		2014		2013	
	Natural Gas (Mcf)	Oil and Condensate (Bbls)	Natural Gas (Mcf)	Oil and Condensate (Bbls)	Natural Gas (Mcf)	Oil and Condensate (Bbls)
Production						
Underlying Properties	29,128,439	63,588	30,872,147	60,002	31,711,193	55,857
Royalty	7,964,174	18,737	15,303,435	30,112	10,131,009	18,308
Average Price (per Mcf/Bbl)	$ 2.60	$ 47.00	$ 4.47	$ 82.99	$ 3.88	$ 86.38

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Production costs for natural gas attributable to the Underlying Properties for the three years ended December 31, 2015 were as follows:

	2015	2014	2013
Total Production Costs (Including Capital Expenses)	$ 51,026,905	$ 60,278,902	$ 73,909,480
Average Production Costs per Unit of Production	$ 1.7518	$ 1.9525	$ 2.3307
Lease Operating Expenses	$ 30,061,218	$ 34,575,374	$ 37,820,636
Average Lifting Cost per Unit of Production	$ 1.0320	$ 1.1200	$ 1.1927

The Trust recognizes production during the month in which the related net proceeds attributable to the Royalty are paid to the Trust. Royalty Income for a calendar year is based on the actual natural gas and oil production during the period beginning with November of the preceding calendar year through October of the current calendar year. Sales volumes attributable to the Royalty are determined by dividing the net profits by the Trust from the sale of oil and natural gas, respectively, by the prices received for sales of such volumes from the Underlying Properties, taking into consideration production taxes attributable to the Underlying Properties. Because the oil and natural gas sales attributable to the Royalty are based upon an allocation formula dependent on such factors as price and cost, including capital expenditures, the aggregate sales amounts from the Underlying Properties may not provide a meaningful comparison to sales attributable to the Royalty.

The fluctuations in annual natural gas production that have occurred during these three years generally resulted from changes in the demand for natural gas during that time, market conditions, and variances in capital spending to generate production from new and existing wells, as offset by the natural production decline curve. Also, production from the Underlying Properties is influenced by the line pressure of the natural gas gathering systems in the San Juan Basin. As noted above, oil and natural gas sales attributable to the Royalty are based on an allocation formula dependent on many factors, including oil and natural gas prices and capital expenditures.

Marketing

Natural gas produced in the San Juan Basin is sold in both interstate and intrastate commerce. Reference is made to the discussion contained herein under Regulation for information as to federal regulation of prices of oil and natural gas.

Natural gas produced from the Underlying Properties is processed at the: Chaco, Val Verde, Milagro, Ignacio or Kutz plants, all located in the San Juan Basin. All such natural gas, other than that processed at Kutz, is sold to Chevron USA, Inc. (Chevron) under a contract with Burlington dated April 1, 2015 that will terminate on March 31, 2016. Burlington has solicited requests for proposal for the purchase of the volumes covered by that contract beginning April 1, 2016.

Natural gas produced from the Underlying Properties and processed at Kutz was being sold under two separate contracts with EDF Trading North America, LLC (EDF) and New Mexico Gas Company, Inc. (NMGC). The NMGC contract for the sale of certain winter-only supplies of the Kutz natural gas is for a five-year term expiring March 31, 2017. Burlington s contract with EDF terminates on March 31, 2016, and Burlington has solicited requests for proposal for the purchase of those volumes beginning April 1, 2016.

All three of the current natural gas purchase contracts provide for (i) the delivery of such natural gas at various delivery points through their respective termination dates; and (ii) the sale of such natural gas at prices that fluctuate in accordance with published indices for natural gas sold in the San Juan Basin of northwestern New Mexico.

Burlington contracts with Williams Four Corners, LLC (WFC) and Enterprise Field Services, LLC (EFS) for the gathering and processing of virtually all of the natural gas produced from the Underlying Properties. Four new contracts were entered into with WFC, each of which is effective for a term of 15 years,

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which commenced April 1, 2010. Burlington has signed a similar agreement with EFS which was effective November 1, 2011 for a term of 15 years. Burlington has disclosed to the Trust a summary of that agreement which the Trust has reviewed with its consultants, subject to conditions of confidentiality.

The Trust is not a party to any of the purchase, gathering or processing contracts. As part of the 1996 settlement of litigation filed by the Trustee in 1992 against Burlington and Southland, the Trustee and Burlington established a formal protocol pursuant to which compliance auditors retained by the Trustee have access to Burlington s books and records.

Oil and Natural Gas Reserves

Proved Reserves

All of the Trust s reserves are located in the San Juan Basin of northwestern New Mexico. Total proved developed and undeveloped oil and natural gas reserves as of December 31, 2015 were as follows:

	Proved Reserves(1)(2)	
Reserves Category	**Natural Gas (MMcf)**	**Crude Oil and Condensate (MBbls)**
Developed	75,572	170
Undeveloped	-	-
Total Proved	75,572	170

(1) Proved reserves were calculated using prices equal to the twelve-month unweighted arithmetic average of the first-day-of-the-month commodity prices for each of the preceding twelve months, which were $2.59 per MMBtu (Henry Hub) of natural gas and $50.28 per Bbl (West Texas Intermediate) of oil. The adjusted volume-weighted average prices over the life of the properties were $2.29 per Mcf of gas and $36.48 per Bbl of oil.

(2) Since the Trust has a defined net overriding royalty interest, the Trust does not own a specific percentage of the oil and gas reserves. Because Trust reserve quantities are determined using an allocation formula, any fluctuations in actual or assumed prices or costs will result in revisions to the estimated reserve quantities allocated to the net overriding royalty interest.

Estimated quantities of proved developed oil and natural gas reserves as of December 31, 2015, 2014 and 2013 were as follows:

	2015	**2014**	**2013**
Natural Gas (MMcf)	75,572	118,594	103,405
Crude Oil and Condensate (MBbls)	170	268	189

Proved Undeveloped Reserves

Based on information provided by Burlington and analysis by our independent reserve engineer, there were no proved undeveloped reserves identified as of December 31, 2015, as compared to 2.2 Bcf of natural gas proved undeveloped reserves as of December 31, 2014. The reduction in proved undeveloped reserves is due to negative price revisions attributed to the low commodity price outlook and reduced future development activity.

Internal Controls over Reserves Estimates

The process of estimating oil and natural gas reserves is complex and requires significant judgment. The Trust, however, does not have information that would be available to a company with oil and natural gas operations because detailed information is not generally available to owners of royalty interests. Given this, the

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Trustee accumulates information and data provided by Burlington regarding the Royalty derived from the Underlying Properties and provides such information to Cawley, Gillespie & Associates, Inc. (CG&A). CG&A extrapolates from such information estimates of the reserves attributable to the Underlying Properties based on its expertise in the oil and natural gas fields where the Underlying Properties are situated, as well as publicly available information. The Trust maintains internal controls and procedures applicable to reserve estimation which are reviewed annually and updated as required and reviews the reserve reports prepared by CG&A for reasonableness. The Trust s internal controls and procedures regarding reserve estimates require proved reserves to be determined and disclosed in compliance with the SEC definitions and guidance.

Third-Party Reserves

The Trust does not maintain an internal petroleum engineering department and instead relies upon CG&A for a qualified, independent report of estimated reserves. The Trust verifies the qualifications and credentials of CG&A to prepare reserve estimates on behalf of the Trust. The independent petroleum engineers reports as to the proved oil and natural gas reserves as of December 31, 2012, 2013, 2014 and 2015 were prepared by CG&A. CG&A, whose firm registration number is F-693, was founded in 1961 and is nationally recognized in the evaluation of oil and natural gas properties. The technical person at CG&A primarily responsible for overseeing the reserve estimate with respect to the Trust is Zane Meekins. Mr. Meekins has been a practicing petroleum engineering consultant since 1989, with over 28 years of practice experience in petroleum engineering. He is a registered professional engineer in the State of Texas (License No. 71055). He graduated from Texas A&M University in 1987, *summa cum laude*, with a B.S. in Petroleum Engineering. CG&A and Mr. Meekins have indicated that they meet or exceed all requirements set forth in Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

Regulation

General

Exploration for and production and sale of oil and natural gas are extensively regulated at the national, state, and local levels. These laws may govern a wide variety of matters, including allowable rates of production, transportation, marketing, pricing, well construction, water use, prevention of waste, waste disposal, pollution and protection of the environment. These laws, regulations and orders have in the past, and may again, restrict the rate of oil and natural gas production below the rate that would otherwise exist in the absence of such laws, regulations and orders.

Laws affecting the oil and natural gas industry and the distribution of its products are under constant review for amendment or expansion, frequently increasing the regulatory burden on operations. Numerous governmental departments and agencies are authorized by statute to issue, and have issued, rules and regulations binding on the oil and natural gas industry. Compliance with applicable laws is often difficult and costly, while non-compliance may result in substantial penalties.

Natural Gas

The transportation and sale for resale of natural gas in interstate commerce, historically, have been regulated pursuant to several laws enacted by Congress and the regulations promulgated under these laws by the Federal Energy Regulatory Commission (FERC) and its predecessor. In the past, the federal government has regulated the prices at which natural gas could be sold in interstate commerce. Congress removed all price and non-price controls affecting wellhead sales of natural gas under the Natural Gas Wellhead Decontrol Act effective January 1, 1993. Congress could, however, reenact controls in the future.

Sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for pipeline transportation remain subject to extensive federal and state regulation. Several major regulatory changes have been implemented by Congress and FERC from 1985 to the present that affect the economics of natural gas

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production, transportation and sales. In addition, FERC continues to promulgate revisions to various aspects of the rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies, that remain subject to FERC s jurisdiction. These initiatives may also affect the intrastate transportation of gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry.

Additional proposals and proceedings that might affect the natural gas industry are considered from time to time by Congress, FERC, state regulatory bodies and the courts. The Trust cannot predict when or if any such proposals might become effective, or their effect, if any, on the Trust. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach to natural gas sales pursued since 1993 by FERC and Congress will continue.

Sales of crude oil, condensate and gas liquids are not currently regulated and are made at market prices. The ability to transport and sell petroleum products depends on pipelines that transport such products in interstate commerce and FERC regulates the rates, terms and conditions of service by such pipelines under the Interstate Commerce Act.

Environmental Regulation

General. Activities on the Underlying Properties are subject to existing stringent and complex federal, state and local laws (including case law) and regulations governing health, safety, environmental quality and pollution control. Failure to comply with these laws, rules and regulations, however, 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.

Cleanup. Under certain environmental laws and regulations, the operators of the Underlying Properties could be subject to strict, joint and several liability for the removal or remediation of property contamination, whether at a drill site or a waste disposal facility, even when the operators did not cause the contamination or their activities were in compliance with all applicable laws at the time the actions were taken. The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as the superfund law, for example, imposes liability, regardless of fault or the legality of the original conduct, on certain classes of persons for releases into the environment of a hazardous substance. Liable persons may include the current or previous owner and operator of a site where a hazardous substance has been disposed and persons who arranged for the disposal of a hazardous substance at a site. Under CERCLA and similar statutes, government authorities or private parties may take actions in response to threats to the public health or the environment or sue responsible persons for the associated costs. In the course of operations, the working interest owner and/or the operator of Underlying Properties may have generated and may generate materials that could trigger cleanup liabilities. In addition, the Underlying Properties have produced oil and/or natural gas for many years, and previous operators may have disposed or released hydrocarbons, wastes or hazardous substances at the Underlying Properties. The operator of the Underlying Properties or the working interest owners may be responsible for all or part of the costs to clean up any such contamination. Although the Trust is not the operator of any Underlying Properties, or the owner of any working interest, its ownership of the Royalty could cause it to be responsible for all or part of such costs to the extent CERCLA or any similar statute imposes responsibility on such parties as owners.

Climate Change. In December 2009, the EPA determined that emissions of carbon dioxide, methane and certain other greenhouse gases (GHGs) endanger public health and the environment because emissions of such gases are contributing to warming of the Earth s atmosphere and other climatic changes. Based on those findings, the EPA has been adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the Clean Air Act (CAA). The EPA has already adopted rules under the CAA that, among other things, cover reductions in GHG emissions from motor vehicles, permits for certain large stationary sources of GHGs, monitoring and annual reporting of GHG emissions from specified GHG emission sources, including oil and

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natural gas exploration and production operations, and power plant performance standards that are designed to lead to the creation of additional state GHG control programs. In June 2013, moreover, President Obama unveiled a Presidential climate action plan designed to reduce emissions in the US of methane, carbon dioxide and other GHGs. In furtherance of that plan, the Obama Administration has launched a number of initiatives, including a Strategy to Reduce Methane Emissions from the oil and natural gas industry. The Administration s goal is to reduce methane emissions from the oil and natural gas industry by 40-45% by 2025 as compared to 2012 levels. The EPA therefore issued a proposed rule in the summer of 2015 that would set additional standards for methane and volatile organic compound emissions from oil and natural gas production sources, including hydraulically fractured oil wells, and natural gas processing and transmission sources. The EPA intends to issue a final rule in 2016. As another prong of the Administration s methane strategy, the Bureau of Land Management has proposed standards for reducing venting and flaring on public lands. Various state governments and regional organizations comprising state governments similarly have enacted legislation and promulgated regulations restricting GHG emissions or promoting the use of renewable energy, and additional such measures are frequently under consideration. Although it is not possible at this time to estimate how potential future laws or regulations addressing GHG emissions would impact operations on the Underlying Properties and Royalty Income, either directly or indirectly, any future federal, state or local laws or implementing regulations that may be adopted to address GHG emissions could require the operator of the Underlying Properties to incur new or increased costs to obtain permits, operate and maintain equipment and facilities, install new emission controls, acquire allowances to authorize GHG emissions, pay taxes related to GHG emissions or administer a GHG emissions program. Regulation of GHGs could also result in a reduction in demand for and production of oil and natural gas. Additionally, to the extent that unfavorable weather conditions are exacerbated by global climate change or otherwise, the Underlying Properties may be adversely affected to a greater degree than previously experienced.

Certain Tax Considerations

The classification of the Trust s income for purposes of the passive loss rules may be important to a Unit Holder. As a result of the Tax Reform Act of 1986, royalty income such as that derived through the Trust will generally be treated as portfolio income that may not be offset or reduced by passive losses.

The Trustee has been informed that the New Mexico Oil and Gas Proceeds and Pass-Through Entity Withholding Tax Act (the Withholding Tax Act) requires remitters who pay certain oil and natural gas proceeds from production on New Mexico wells to withhold income taxes from such proceeds in the case of certain nonresident recipients. The Trustee, on advice of New Mexico counsel, has observed that net profits interests, such as the Royalty, and other types of interests, the extent of which cannot be determined with respect to a specific share of the oil and natural gas production, as well as amounts deducted from payments that are for expenses related to oil and natural gas production, are excluded from the withholding requirements of the Withholding Tax Act. Unit Holders are reminded to consult with their tax advisors regarding the applicability of New Mexico income tax to distributions received from the Trust by a Unit Holder.

ITEM 3. ***LEGAL PROCEEDINGS***

As discussed herein under Part II, Item 9A (Controls and Procedures), due to the pass-through nature of the Trust, Burlington is the primary source of the information disclosed in this Annual Report on Form 10-K and the other periodic reports filed by the Trust with the SEC. Although the Trustee receives periodic updates from Burlington regarding activities which may relate to the Trust, the Trust s ability to timely report certain information required to be disclosed in the Trust s periodic reports is dependent on Burlington s timely delivery of the information to the Trust.

Burlington Matter

On July 31, 2014, the Trustee filed a lawsuit (the 2014 Litigation) against Burlington in New Mexico State Court. The Trust asserts claims for breach of contract and breach of the implied covenant of good faith and fair dealing, and seeks a declaratory judgment arising out of a number of unresolved revenue and expense audit exceptions asserted by the Trust s auditors. More particularly, the Trust claims that Burlington failed to properly account for and pay net overriding royalty interests to the Trust with respect to oil and natural gas production from numerous properties in the San Juan Basin of northwestern New Mexico. The Trust seeks monetary relief (including actual and punitive damages, costs, expenses, interest and attorney fees) in excess of $12 million, along with specific performance of certain contractual obligations, declaratory relief and a judgment for other relief to which it may show itself to be justly entitled. Burlington has filed an answer and denies liability. The parties have commenced written discovery and depositions, and are working to schedule mediation. The case is currently set for non-jury trial in September 2016.

In addition, Burlington notified the Trust in March 2008 that the distribution for that month would be reduced by approximately $4.9 million. Burlington described this amount as the Trust s portion of what Burlington had paid to settle certain *qui tam* claims asserted by the government for the underpayment of royalties (the *Qui Tam* Settlement). The Trust has objected to Burlington s unilateral decision to deduct any amount of the *Qui Tam* Settlement paid by Burlington from the distributions payable to the Trust and formally complained of that action as part of the 2014 Litigation. The Trust argues that no part of the *Qui Tam* Settlement should have been allocated to the Trust because the claim that gave rise to the settlement was presented to Burlington for payment or otherwise known to Burlington prior to the effective date of a mutual release of all claims entered into by Burlington and the Trust in 1996 (the 1996 Settlement). In the alternative, the Trust contends that (a) those portions of the royalty underpayment claims involved in the *Qui Tam* Settlement that had accrued and existed as of the date of the 1996 Settlement, whether known or unknown, were released by the 1996 Settlement, or (b) even if Burlington s allocation of part of the *Qui Tam* Settlement was not barred by the mutual release in the 1996 Settlement, the amount allocated to the Trust by Burlington was improper and excessive.

Jicarilla Matter

Burlington has informed the Trust that pursuant to an Order to Perform issued by the Minerals Management Service, (MMS), dated June 10, 1998 (the MMS Order), the Jicarilla Apache Nation (the Jicarilla) alleged that in valuing production for royalty purposes one must perform (i) a major portion analysis, which calculates value on the highest price paid or offered for a major portion of the natural gas produced from the field where the leased lands are situated; and (ii) a dual accounting calculation, which computes royalties on the greater of (a) the value of natural gas prior to processing or (b) the combined value of processed residue natural gas and plant products plus the value of any condensate recovered downstream without processing. The MMS Order alleged that Burlington s dual accounting calculations on Native American leases were based on less than major portion prices. In 2000, Burlington and the Jicarilla entered into a settlement agreement resolving the issues associated with the dual accounting calculation. The major portion calculation issue remains outstanding. Burlington takes the position that a judgment or settlement could entitle Burlington to reimbursement from the Trust for past periods.

In 2007 Burlington obtained an Administrative Order from the Department of the Interior (the DOI) rejecting that portion of the MMS Order requiring Burlington to calculate and pay additional royalties based on the major portion price derived by the MMS. The Jicarilla filed suit solely against the DOI in the United States District Court for the District of Columbia (the DOI Case) seeking a declaration that the Administrative Order is unlawful and of no force and effect, as well as an injunction requiring enforcement of the underlying major portion orders that were rejected by the Assistant Secretary. In 2009, a summary judgment was entered by the district court in the DOI Case upholding the Administrative Order and dismissing the Jicarilla s claims. The Jicarilla appealed to the U.S. Court of Appeals for the D.C. Circuit, which held that the 2007 Administrative Order dismissing the Jicarilla claims was arbitrary and capricious with respect to January 1984 through February

1988 production periods and remanded the matter to the DOI for further proceedings. While a judgment or settlement in the DOI Case could impact the Royalty Income of the Trust, Burlington has informed the Trust that it does not have sufficient information to estimate a range of loss for the Trust because the DOI has not provided a major portion calculation for the January 1984 to February 1988 time period as required by the Court of Appeals ruling. Burlington indicates that the situation will not be alleviated until the DOI provides Burlington with a new Order to Perform or similar notice, but that it cannot predict when or if the DOI will provide such information or notice. The Trust s consultants will continue to monitor development in this matter and analyze the appropriateness of the allocation, if any, by Burlington of any portion of any settlement or judgment in calculating the Royalty.

ITEM 4. ***MINE SAFETY DISCLOSURES***

Not applicable.

PART II

ITEM 5. *MARKET FOR REGISTRANT S UNITS, RELATED UNIT HOLDER MATTERS AND ISSUER PURCHASES OF UNITS*

Units of Beneficial Interest

The units of beneficial interest of the Trust (the Units) are traded on the New York Stock Exchange under the symbol SJT. The Trust makes monthly cash distributions to the Unit Holders. The aggregate monthly distribution amount is the excess of (i) the net proceeds attributable to the Royalty paid to the trustee of the Trust, plus any decrease in cash reserves previously established for liabilities and contingencies of the Trust, over (ii) the expenses and payments of liabilities of the Trust, plus any net increase in cash reserves. Future payments of cash distributions are dependent on such factors as prevailing natural gas and oil prices, expenses, and the actual production from the Underlying Properties.

Unit Prices and Distributions by Quarters

From January 1, 2014, to December 31, 2015, the quarterly high and low sales prices and the aggregate amount of monthly distributions paid per Unit paid each quarter were as follows:

	Sales Price		
2015	**High**	**Low**	**Distributions Paid**
First Quarter	$ 15.85	$ 11.75	$ 0.145098
Second Quarter	12.50	10.35	0.030385
Third Quarter	11.41	8.25	0.107567
Fourth Quarter	9.74	3.99	0.081695
Total for 2015			**$ 0.364745**

	Sales Price		
2014	**High**	**Low**	**Distributions Paid**
First Quarter	$ 18.25	$ 16.44	$ 0.302300
Second Quarter	20.25	17.33	0.380019
Third Quarter	19.57	16.25	0.336690
Fourth Quarter	19.22	13.62	0.265578
Total for 2014			**$ 1.284587**

According to the records of our transfer agent, as of February 16, 2016, there were 46,608,796 Units outstanding held by 1,093 Unit Holders of Record. The actual number of Unit Holders is greater than these numbers of Unit Holders of record and includes Unit Holders who are beneficial owners, but whose shares are held in street name by brokers and nominees. The number of Unit Holders of record also does not include Unit Holders whose Units may be held in trust by other entities.

Equity Compensation Plans

The Trust has no directors, executive officers or employees. Accordingly, the Trust does not maintain any equity compensation plans and there are no Units reserved for issuance under any such plans.

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ITEM 6. ***SELECTED FINANCIAL DATA***

The following table sets forth selected data for the Trust based on the audited statements of distributable income for the years indicated and the audited statements of assets, liabilities and trust corpus as of December 31 of the years indicated.

	For the year ended December 31,				
	2015	**2014**	**2013**	**2012**	**2011**
Royalty Income	$ 19,436,768	$ 61,507,662	$ 38,042,603	$ 34,485,777	$ 68,029,748
Distributable income	17,000,247	59,873,115	36,492,592	33,481,687	67,190,000
Distributable income per Unit	0.364745	1.284587	0.782955	0.718358	1.441573
Distributions per Unit	0.364745	1.284587	0.782955	0.718358	1.441573

	December 31,				
	2015	**2014**	**2013**	**2012**	**2011**
Trust corpus	$ 8,724,387	$ 9,362,757	$ 10,968,996	$ 12,163,460	$ 13,145,058
Total assets	10,543,639	13,374,097	15,619,678	13,583,556	20,246,377

ITEM 7. ***TRUSTEE S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS***

Overview

The principal asset of the Trust is the Royalty, which consists of a 75% net overriding royalty interest that burdens Underlying Properties located in the San Juan Basin of northwestern New Mexico. The primary function of the Trustee is to collect the Royalty Income, to pay all expenses and charges of the Trust and to distribute the remaining available income to the Unit Holders. The amount of income distributable to Unit Holders, which we refer to as Distributable Income, depends on the amount of Royalty Income and interest received by the Trust, as well as the amount of expenses paid by the Trust and any change in cash reserves.

Royalty Income. The Royalty functions generally as a net profits interest in the Underlying Properties. The Royalty Income paid to the Trust is 75% of net proceeds from the Underlying Properties. The term net proceeds, as used in the Conveyance, means the excess of gross proceeds received by Burlington during a particular period over production costs for such period. Gross proceeds means the amount received by Burlington (or any subsequent owner of the Underlying Properties) from the sale of the production attributable to the Underlying Properties, subject to certain adjustments.

The amount of gross proceeds attributable to the Underlying Properties depends on prevailing natural gas prices and, to a lesser extent, crude oil prices. As a result, commodity prices affect the amount of Royalty Income available for distribution to the Unit Holders. In 2015, oil and natural gas prices exhibited significant volatility. During 2015, the price of natural gas and oil for production from the Underlying Properties declined significantly from an average price for natural gas of $4.47 per Mcf in 2014 to $2.60 per Mcf in 2015, and the price for oil declined from an average price of $82.99 per Bbl in 2014 to $47.00 per Bbl in 2015. The recent significant decline in oil and natural gas prices increases the uncertainty as to the impact of commodity prices on our estimated proved reserves. A prolonged period of depressed commodity prices may have a significant impact on the volumetric quantities of oil and natural gas attributable to the Underlying Properties.

The amount of gross proceeds also depends on the volumes of natural gas and oil produced from the Underlying Properties. Under the terms of the Indenture, the Trust cannot acquire new natural gas and oil assets, and as a result, Royalty Income is dependent on the natural gas and oil volumes attributable to the Underlying Properties. Although Burlington and other operators of the Underlying Properties continue to drill wells, the Underlying Properties are depleting assets, and Burlington informs us it is unable to estimate the productive life of the Underlying Properties. In addition, drilling activity was significantly reduced in 2015 and Burlington has not budgeted any capital expenditures for new drilling in 2016. Lower commodity prices may also reduce the volume of natural gas and oil produced from the Underlying Properties.

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Under the terms of the Conveyance, production costs are deducted from gross proceeds in calculating Royalty Income. Production costs generally means costs incurred on an accrual basis by Burlington in operating the Underlying Properties, including both capital and non-capital costs. For example, these costs include development drilling, production and processing costs, applicable taxes and operating charges. If production costs exceed gross proceeds in any month, the excess is recovered out of future gross proceeds prior to the making of further payment to the Trust, but the Trust is not otherwise liable for any production costs or other costs or liabilities attributable to the Underlying Properties or the minerals produced therefrom. If at any time the Trust receives more than the amount due under the Royalty, it is not obligated to return such overpayment, but the amounts payable to it for any subsequent period are reduced by such amount, plus interest, at a rate specified in the Conveyance. The Trust and the Trustee has very limited authority to control the amount and timing of production costs.

Distributable Income. In addition to Royalty Income, the Trust receives interest income, typically from interest paid on cash deposits and interest paid by Burlington on audit exceptions. General and administrative expenses constitute the Trust s primary expense and include, among other items, the Trustee s fees, audit, consulting and legal fees and reporting costs.

The Trustee is authorized to determine in its discretion the amount of cash reserves needed to pay liabilities and contingencies of the Trust. The amount of distributions to Unit Holders in a period is reduced by the amount of any increase in cash reserves for that period. Because continued volatility in oil and natural gas prices may result in decreases in Royalty Income during 2016, the Trustee is monitoring the cash needs of the Trust and plans to increase the amount of cash reserves. The Trustee has increased the amount of cash reserves during 2016 by $150,000 as of February 29, 2016 and expects to further increase the total amount of cash reserves to approximately $1.0 million during the year.

Results of Operations

Royalty Income

Royalty Income consists of monthly net proceeds attributable to the Royalty. Royalty Income for the three years ended December 31, 2015 was determined as shown in the following table:

	For the years ended December 31,		
	2015	**2014**	**2013**
Gross Proceeds From The Underlying Properties:			
Natural Gas	$ 74,129,258	$ 137,324,791	$ 118,276,065
Oil	2,803,231	4,964,328	4,721,365
Other	10,107	-	-
Total	76,942,596	142,289,119	122,997,430
Capital Expenditures	12,813,526	6,531,316	21,470,626
Severance Tax Natural Gas	7,548,915	18,162,866	11,748,779
Severance Tax Oil	268,400	507,433	483,018
Other	-	-	4,430(1)
Lease Operating Expenses and Property Taxes	30,396,064	35,077,288	38,567,106
Total	51,026,905	60,278,903	72,273,959
Net Profits	25,915,691	82,010,216	50,723,471
Net Overriding Royalty Interest	75%	75%	75%
Royalty Income	$ 19,436,768	$ 61,507,662	$ 38,042,603

(1) Interest on excess production cost.

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Gross Proceeds from Underlying Properties. Gross proceeds decreased $65.4 million or 46% to $76.9 million for the year ended December 31, 2015 compared to $142.3 million for the year ended December 31, 2014. The decrease was primarily attributable to lower natural gas and oil prices. Other proceeds were comprised of $2,429 additional revenue for the settlement of a natural gas imbalance, a $3,301 settlement award and $7,407 in an audit exception granted by Burlington for ad valorem taxes, offset against $3,030 owed to Burlington for duplicate payment of interest due on granted and paid audit exceptions. Gross proceeds increased $19.3 million or 16% to $142.3 million for the year ended December 31, 2014 compared to $123.0 million for the year ended December 31, 2013. The increase was primarily attributable to higher natural gas prices.

Capital Expenditures. The capital expenditures reported by Burlington in a given year include amounts attributable to the capital budgets for prior years because capital expenditures are deducted in calculating Royalty Income in the month they accrue, and projects within a given year s budget often extend into subsequent years. Further, Burlington s accounting period for capital expenditures runs through November 30 of each calendar year, such that capital expenditures incurred in December of each year are actually accounted for as part of the following year s capital expenditures. In addition, with respect to wells not operated by Burlington, Burlington s share of capital expenditures may not actually be paid by it until the year or years after those expenses were incurred by the operator.

Capital expenditures increased $6.3 million or 96% from $6.5 million for the year ended December 31, 2014 compared to $12.8 million for the year ended December 31, 2015. Capital expenditures in 2015 included expenditures for the drilling of nine gross (5.75 net) conventional wells. All of the wells commenced in 2015 were development wells. There were no dry exploratory or development wells drilled in 2015. Approximately $5.2 million of capital expenditures for 2015 covered 38 projects budgeted for prior years, including continued work on five new wells commenced in the years prior to 2015, all operated by Burlington, and 33 maintenance and facilities projects. The approximately $7.6 million balance for 2015 expenditures was attributable to six operated new drill projects, and 34 projects for the maintenance and improvement of production facilities.

Capital expenditures decreased $14.9 million or 70% from $21.5 million for the year ended December 31, 2013 compared to $6.5 million for the year ended December 31, 2014. Capital expenditures of $6.5 million were included in calculating Royalty Income paid to the Trust in calendar year 2014 and included expenditures for the drilling of five gross (3.2 net) conventional wells. All five of such conventional wells were commenced in the fourth quarter 2014. Two gross (1.13 net) wells were completed, and three gross (2.1 net) wells were still in progress as of December 31, 2014. Burlington reports that a sixth conventional well was spud before December 31, 2014 which, by Burlington s convention, was accounted for as attributable to the capital budget for 2015. All of the wells commenced in 2014 were development wells. There were no dry exploratory or development wells drilled in 2014. Approximately $1.8 million of capital expenditures covered 103 projects budgeted for prior years, including continued work on 49 new wells commenced in the years prior to 2014, all operated by Burlington, and 54 maintenance and facilities projects. The approximately $4.7 million balance for 2014 expenditures was attributable to five operated new drill projects, and 41 projects for the maintenance and improvement of production facilities.

Severance Taxes. Aggregate severance taxes decreased $10.9 million or 58% to $7.8 million for the year ended December 31, 2015 compared to $18.7 million for the year ended December 31, 2014. Aggregate severance taxes increased $6.4 million or 53% to $18.7 million for the year ended December 31, 2014 compared to $12.2 million for the year ended December 31, 2013. In February 2014, Burlington informed the Trustee that it had discovered a failure by Burlington to properly allocate approximately $4.3 million of severance taxes to the calculation of the Royalty during a period commencing in 2007 until the error was corrected in 2012, which resulted in what it characterized as an overpayment to the Trust in the amount of approximately $3.25 million. Burlington recouped the overpayment in equal installments from March through November 2014, which resulted in higher severance taxes for 2014. Burlington elected not to charge interest against the overpayment.

Lease Operating Expenses and Property Taxes. Lease operating expenses and property taxes decreased $4.7 million or 13% to $30.4 million for the year ended December 31, 2015 compared to $35.1 million for the year ended December 31, 2014. The decrease was primarily attributable to Burlington s efforts to reduce contracted maintenance and repair costs as a result of declining commodity prices, which began in 2014. Lease operating expenses and property taxes decreased $3.5 million or 9% to $35.1 million for the year ended December 31, 2014 compared to $38.6 million for the year ended December 31, 2013. The decrease was primarily attributable to reductions in contracted maintenance and repair costs.

Monthly operating expenses of the Underlying Properties, exclusive of property taxes, in 2015 averaged approximately $2.5 million, as compared to $2.9 million in 2014. Operating expenses averaged lower in 2015 primarily because of reduced maintenance and repair labor. Monthly operating expenses of the Underlying Properties, exclusive of property taxes, in 2014 averaged approximately $2.9 million, compared to $3.2 million in 2013. Operating expenses averaged lower in 2014 primarily because of reduced maintenance and repair costs.

Distributable Income

	For the year ended December 31,		
	2015	**2014**	**2013**
Royalty Income	$ 19,436,768	$ 61,507,662	$ 38,042,603
Interest Income	81,985	75,835	3,413
Total Income	19,518,753	61,583,497	38,046,016
Expenditures General and Administrative	2,168,435	1,710,382	1,523,906
Increase in Cash Reserves	350,071	-	29,518
Distributable Income	$ 17,000,247	$ 59,873,115	$ 36,492,592
Distributable Income per Unit (46,608,796 Units)	$ 0.364745	$ 1.284587	$ 0.782955

Distributable Income decreased $42.9 million or 72% to $17.0 million ($0.364745 per Unit) for the year ended December 31, 2015 from $59.9 million ($1.284587 per Unit) for the year ended December 31, 2014. The decrease in Distributable Income from 2014 to 2015 was primarily attributable to a decrease in Royalty Income over the same period as a result of lower natural gas pricing and higher capital expenditures in 2015. No distributions were made for April or May 2015 because general and administrative expenses exceeded Royalty Income in April and all Royalty Income for May was applied to general and administrative expenses and to replenish cash reserves.

Distributable Income increased $23.4 million or 64% to $59.9 million ($1.284587 per Unit) for the year ended December 31, 2014 from $36.5 million ($0.782955 per Unit) for the year ended December 31, 2013. The increase in Distributable Income from 2013 to 2014 was primarily attributable to higher natural gas pricing and lower capital expenditures in 2014. No distributions were made for March or April 2013 because general and administrative expenses exceeded Royalty Income in March and all Royalty Income for April was applied to general and administrative expenses and to replenish cash reserves.

Interest Income. Interest Income in 2015 was higher as compared to 2014 primarily due to additional interest Burlington paid to the Trust in 2015 as a result of the granting of certain audit exceptions. Interest Income in 2014 was higher as compared to 2013, primarily due to additional interest received in 2014 on late payments of Gross Proceeds used in the calculation of the Royalty. Interest Income in 2015 and 2014 includes $78,884 and $69,241 of interest, respectively, on the late payment of gross proceeds as a result of the ongoing negotiation of compliance audit issues.

General & Administrative Expenses. General and administrative expenses increased $0.5 million or 27% to $2.2 million for the year ended December 31, 2015 compared to $1.7 million for the year ended December 31, 2014. The increase was primarily attributable to differences in timing in the receipt and payment of certain of these expenses as well as increased audit costs and legal costs incurred related to the Burlington

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litigation. General and administrative expenses increased $0.2 million or 12% to $1.7 million for the year ended December 31, 2014 compared to $1.5 million for the year ended December 31, 2013. The increase was primarily attributable to differences in timing in the receipt and payment of certain of these expenses as well as increased audit costs and legal costs incurred related to the Burlington litigation.

Cash Reserves. Total cash reserves were approximately $0.5 million, $0.2 million and $0.2 million as of December 31, 2015, 2014 and 2013, respectively. Cash reserves were increased by $350,071 during 2015 in order to cover expenses in case of a future revenue shortfall resulting from lower commodity prices. In April 2015, royalty income was insufficient to cover Trust expenses, and $97,648 in cash reserves were used. Cash available for distribution in May was first applied to pay Trust expenses and replenish the cash reserve, resulting in no Distributable Income for May 2015. Cash reserves were not increased in 2014.

In March 2013, production costs exceeded revenues, and the cash reserve of $155,789 was completely depleted to pay expenses. The cash available for distribution in April 2013 was applied first to pay certain deferred administrative costs and to replenish the cash reserve. No distributions were made in March or April 2013. There was a $29,518 net increase in cash reserves in 2013 to cover future revenue shortfalls.

Liquidity and Capital Resources

The Trust s principal source of liquidity and capital is Royalty Income. The Trust s distribution of income to Unit Holders is funded by Royalty Income after payment of Trust expenses. The Trust is not liable for any production costs or liabilities attributable to the Royalty. If at any time the Trust receives more than the amount due under the Royalty, it is not obligated to return such overpayment, but the amounts payable to it for any subsequent period are reduced by such amount, plus interest, at a rate specified in the Conveyance. If the Trustee determines that the Trust does not have sufficient funds to pay its liabilities, the Trustee may borrow funds on behalf of the Trust, in which case no distributions will be made to Unit Holders until such borrowings are repaid in full. The Trustee may not sell or dispose of any part of the assets of the Trust without the affirmative vote the Unit Holders of 75% of all of the Units outstanding; however, the Trustee may sell up to 1% of the value of the Royalty (as determined pursuant to the Indenture) during any 12-month period without the consent of the Unit Holders.

2016 Capital Expenditure Budget

Burlington has informed the Trust that its budget for capital expenditures for the Underlying Properties in 2016 is estimated to be $4.8 million. Burlington reports that based on its actual capital requirements, the pace of regulatory approvals, the mix of projects and swings in the price of natural gas, the actual capital expenditures for 2016 are subject to change.

Burlington s announced 2016 capital plan for the Underlying Properties anticipates capital expenditures of $4.8 million, of which $3.4 million is allocated to 20 facilities projects and $1.4 million is allocated to 20 facilities projects attributable to the budgets for prior years. Primarily due to depressed pricing for natural gas, Burlington has not allocated any capital expenditures for 2016 to its drilling program in the San Juan Basin. However, Burlington reported that it continually monitors natural gas prices and plans to restart the program at some point in the future, dependent upon such natural gas prices. Existing wells will continue to be operated.

Contractual Obligations

As of December 31, 2015, the Trust had no obligations or commitments to make future contractual payments other than the trustee fee payable to the trustee. Under the Indenture, the Trustee is entitled to an administrative fee for its administrative services and the preparation of quarterly and annual statements, computed as (i) 1/20 of 1% of the first $100 million of the annual gross revenue of the Trust, and 1/30 of 1% of the annual gross revenue of the Trust in excess of $100 million and (ii) the Trustee s standard hourly rates for time in excess of 300 hours annually. The minimum administrative fee due under items (i) and (ii) is $36,000 per year. Administrative fees paid to the Trustee were approximately $254,395, $310,150 and $259,959 for the years ended December 31, 2015, 2014 and 2013, respectively.

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Off-Balance Sheet Arrangements

None.

Critical Accounting Policies and Estimates

For a description of critical accounting policies and estimates, see Item 8. Financial Statements and Supplementary Date, Note 3.

Results of the 4th Quarters of 2015 and 2014

For the three months ended December 31, 2015, Distributable Income was $3,807,674 ($0.081695 per Unit), which was less than the $12,378,306 ($0.265578 per Unit) of income distributed during the same period in 2014. The decrease in Distributable Income resulted primarily from lower average gas prices and increased administrative expenses in the fourth quarter of 2015.

Royalty Income of the Trust for the fourth quarter is based on actual gas and oil production during August through October of each year. Gas and oil sales for the quarters ended December 31, 2015 and 2014 were as follows:

	2015	2014
Underlying Properties		
Gas Mcf	7,199,985	7,632,393
Mcf per Day	78,261	82,961
Average Price (per Mcf)	$ 2.20	$ 3.97
Oil Bbls	13,046	15,001
Bbls per Day	142	163
Average Price (per Bbl)	$ 32.01	$ 75.95
Attributable to the Royalty		
Gas Mcf	2,161,983	3,570,408
Oil Bbls	3,881	7,058

The average price of gas decreased in the fourth quarter of 2015 compared to the same period of 2014. The price per barrel of oil during the fourth quarter of 2015 was $43.94 lower than the price during the fourth quarter of 2014.

Capital costs for the fourth quarter of 2015 totaled $1,460,942 compared to $2,156,385 during the same period of 2014. Capital costs were dramatically lower in the fourth quarter of 2015 due to Burlington s temporary suspension of its drilling program in the San Juan Basin in March. Capital costs were higher in the fourth quarter of 2014 when Burlington commenced drilling five new wells. Lease operating expenses and property taxes for the fourth quarter of 2015 averaged $2,411,211 per month compared to $2,706,428 per month in the fourth quarter of 2014. Lease operating expenses and property taxes were approximately $295,217 per month lower in the fourth quarter of 2015 than for the fourth quarter of 2014 primarily because of reduced maintenance and repair labor. Based on 46,608,796 Units outstanding, the per-Unit distributions during the fourth quarters of 2015 and 2014 were as follows:

	2015	2014
October	$ 0.037119	$ 0.101222
November	0.017050	0.082288
December	0.027526	0.082068
Quarter Total	$ 0.081695	$ 0.265578

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ITEM 7A. ***QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK***

Interest Rate and Foreign Currency Risk

The Trust invests in no derivative financial instruments, and has no foreign operations or long-term debt instruments. The Trust is a passive entity and is prohibited from engaging in any business or commercial activity of any kind whatsoever, including holding any derivative financial instruments or any borrowing transactions, other than the Trust s ability to borrow money periodically as necessary to pay expenses, liabilities and obligations of the Trust that cannot be paid out of cash reserves held by the Trust. The amount of any such borrowings is unlikely to be material to the Trust. The Trust periodically holds short-term investments acquired with funds held by the Trust pending distribution to Unit Holders and funds held in reserve for the payment of Trust expenses and liabilities. Because of the short-term nature of these borrowings and investments and certain limitations upon the types of such investments which may be held by the Trust, the Trustee believes that the Trust is not subject to material interest rate risk. The Trust does not engage in transactions in foreign currencies which could expose the Trust or Unit Holders to any foreign currency related market risk.

Commodity Price Risk

The Trust s most significant market risk relates to the prices received for natural gas and oil production. The revenues derived from the Underlying Properties depend substantially on prevailing natural gas prices and, to a lesser extent, oil prices. As a result, commodity prices also affect the amount of distributable income to the Unit Holders. Lower prices may also reduce the amount of natural gas and oil that Burlington or the third-party operators can economically produce.

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ITEM 8. ***FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA***

Report of Independent Registered Public Accounting Firm

Compass Bank, Trustee

San Juan Basin Royalty Trust

We have audited the accompanying statements of assets, liabilities and trust corpus of the San Juan Basin Royalty Trust as of December 31, 2015 and 2014, and the related statements of distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2015. 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 conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by the Trustee, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As described in Note 3 to the financial statements, these financial statements were prepared on a modified cash basis of accounting, which is a comprehensive basis of accounting other than generally accepted in the United States of America.

In our opinion, the financial statements referred to above present fairly, in all material respects, the assets, liabilities and trust corpus of the San Juan Basin Royalty Trust as of December 31, 2015 and 2014, and the distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2015, on the basis of accounting described in Note 3 to the financial statements.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), San Juan Basin Royalty Trust s internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated February 29, 2016 expressed an unqualified opinion thereon.

WEAVER AND TIDWELL, L.L.P.

Austin, Texas

February 29, 2016

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Statements of Assets, Liabilities, and Trust Corpus

December 31, 2015 and 2014

	2015	2014
ASSETS		
Cash and Short-Term Investments	$ 1,819,252	$ 4,011,340
Net Overriding Royalty Interests in Producing Oil and Natural Gas Properties Net	8,724,387	9,362,757
TOTAL	$ 10,543,639	$ 13,374,097

	2015	2014
LIABILITIES & TRUST CORPUS		
Distribution Payable to Unit Holders	$ 1,282,939	$ 3,825,098
Cash Reserves	536,313	186,242
Trust Corpus 46,608,796 Units of Beneficial Interest Authorized and Outstanding	8,724,387	9,362,757
TOTAL	$ 10,543,639	$ 13,374,097

Statements of Distributable Income

For each of the years ended December 31

	2015	2014	2013
Royalty Income	$ 19,436,768	$ 61,507,662	$ 38,042,603
Interest Income	81,985(1)	75,835(2)	3,413
Total Income	19,518,753	61,583,497	38,046,016
Expenditures General and Administrative	2,168,435	1,710,382	1,523,906
Increase in Cash Reserves	350,071	-	29,518
Distributable Income	$ 17,000,247	$ 59,873,115	$ 36,492,592
Distributable Income per Unit (46,608,796 Units)	$ 0.364745	$ 1.284587	$ 0.782955

(1) Includes $78,884 interest on the late payment of gross proceeds as a result of the ongoing negotiation of compliance audit issues.

(2) Includes $69,241 in interest on the late payment of gross proceeds as a result of the ongoing negotiation of compliance audit issues.

Statements of Changes in Trust Corpus

For each of the years ended December 31

2015	2014	2013

Trust Corpus, Beginning of Year	$ 9,362,757	$ 10,968,996	$ 12,163,460
Amortization of Net Overriding Royalty Interest	(638,370)	(1,606,239)	(1,194,464)
Distributable Income	17,000,247	59,873,115	36,492,592
Distributions Declared	(17,000,247)	(59,873,115)	(36,492,592)
Trust Corpus, End of Year	$ 8,724,387	$ 9,362,757	$ 10,968,996

These Financial Statements should be read in conjunction with the accompanying Notes to Financial Statements included herein.

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Notes to Financial Statements

1. Trust Organization and Provisions

The San Juan Basin Royalty Trust (the Trust) was established on November 1, 1980. Southland Royalty Company (Southland) conveyed to the Trust a 75% net overriding royalty interest (the Royalty) which burdens certain of Southland s oil and natural gas interests (the Underlying Properties) in properties located in the San Juan Basin in northwestern New Mexico. Subsequent to the Conveyance of the Royalty, through a series of assignments and mergers, Southland s successor became Burlington Resources Oil & Gas Company LP. Burlington is an indirect wholly-owned subsidiary of ConocoPhillips. Through an acquisition completed on March 24, 2006, Compass Bank succeeded TexasBank as Trustee (herein so called) of the Trust. On September 7, 2007, Compass Bancshares, Inc. was acquired by Banco Bilbao Vizcaya Argentaria, S.A. (BBVA) and is now a wholly-owned subsidiary of BBVA.

On November 3, 1980, 46,608,796 units of beneficial interest (Units) in the Trust were distributed to the Trustee for the benefit of Southland shareholders of record as of November 3, 1980, who received one Unit in the Trust for each share of Southland common stock held. The Trust s initial public offering was completed on 1980. The Units are traded on the New York Stock Exchange. Holders of Units are referred to herein as Unit Holders.

The terms of the Trust Indenture provide, among other things, that:

- The Trust shall not engage in any business or commercial activity of any kind or acquire any assets other than those initially conveyed to the Trust;

- The Trustee may sell up to one percent (1%) of the value (based on prior year engineering reports) of the Royalty in any 12 month period, but otherwise may not sell all or any part of the Royalty unless approved by holders of 75% of all Units outstanding. In either case, the sale must be for cash and the proceeds promptly distributed;

- The Trustee may establish a cash reserve for the payment of any liability which is contingent or uncertain in amount;

- The Trustee is authorized to borrow funds to pay liabilities of the Trust;

- The Trustee will make monthly cash distributions to Unit Holders (see Note 2); and

- The Trust will generally terminate upon the first to occur of the following events: (a) at such time as the Trust s gross revenue for each of two successive years is less than $1.0 million per year or (b) the Unit Holders of at least 75% of all of the Units outstanding vote in favor of termination.

2. Net Overriding Royalty Interest and Distribution to Unit Holders

The amounts to be distributed to Unit Holders (Monthly Distribution Amounts) are determined on a monthly basis by the Trustee. The Monthly Distribution Amount is an amount equal to the sum of cash received by the Trustee during a calendar month attributable to the Royalty, any reduction in cash reserves and any other cash receipts of the Trust, including interest, reduced by the sum of liabilities paid and any increase in cash reserves. If the Monthly Distribution Amount for any monthly period is a negative number, then the distribution will be zero for such month and such negative amount will be carried forward and deducted from future monthly distributions until the cumulative distribution calculation becomes a positive number, at which time a distribution will be made. Unit Holders of record will be entitled to receive the calculated Monthly Distribution Amount for each month on or before 10 business days after the monthly record date, which is generally the last business day of each calendar month.

The cash received by the Trustee consists of the proceeds received by the owner of the Underlying Properties from the sale of production less the sum of applicable taxes, accrued production costs, development and drilling costs, operating charges and other costs and deductions, multiplied by 75%.

Notes to Financial Statements (Continued)

The initial carrying value of the Royalty of $133,275,528 represented Southland s historical net book value at the date of the transfer of the Trust. Accumulated amortization as of December 31, 2015 and 2014 was $124,551,141 and $123,912,771, respectively.

No distributions were made for April and May of 2015 because general and administrative expenses exceeded Royalty Income in April, and all Royalty Income for May was applied to general and administrative expenses and to replenish cash reserves. No distributions were made for March and April 2013 because general and administrative expenses exceeded Royalty Income for March, and all Royalty Income for April was applied to general and administrative expenses and to replenish cash reserves.

3. Basis of Accounting

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

The net proceeds attributable to the Royalty (the Royalty Income) recorded for a month is the amount computed and paid by the owner of the Underlying Properties, Burlington Resources Oil & Gas Company LP (Burlington), the present owner of the Underlying Properties, to the Trustee for the Trust. Royalty Income consists of the proceeds received by Burlington from the sale of production less accrued production costs, development and drilling costs, applicable taxes, operating charges, and other costs and deductions, multiplied by 75%. The calculation of net proceeds by Burlington for any month includes adjustments to proceeds and costs for prior months and impacts the Royalty Income paid to the Trust and the distribution to Unit Holders for that month.

Trust expenses recorded are based on liabilities paid and cash reserves established from Royalty Income for liabilities and contingencies.

Distributions to Unit Holders are recorded when declared by the Trustee.

The conveyance which transferred the Royalty to the Trust provides that any excess of production costs applicable to the Underlying Properties over gross proceeds from such properties must be recovered from future net proceeds before Royalty Income is again paid to the Trust.

The financial statements of the Trust differ from financial statements prepared in accordance with United States generally accepted accounting principles (GAAP) because revenues are not accrued in the month of production; certain cash reserves may be established for liabilities and contingencies which would not be accrued in financial statements prepared in accordance with GAAP; expenses are recorded when paid instead of when incurred; and amortization of the Royalty calculated on a unit-of-production basis is charged directly to trust corpus instead of as an expense. Most accounting pronouncements apply to entities whose financial statements are prepared in accordance with U.S. generally accepted accounting principles, directing such entities to accrue or defer revenues and expenses in a period other than when such revenues were received or expenses were paid. Because the trust s financial statements are prepared on the modified cash basis, as described above, most accounting pronouncements are not applicable to the Trust s financial statements. This comprehensive basis of accounting corresponds to the accounting permitted for royalty trusts by the U.S. Securities and Exchange Commission, as specified by Staff Accounting Bulletin Topic 12:E, Financial Statements of Royalty Trusts.

The Trustee routinely reviews its royalty interests in oil and gas properties for impairment whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. If an impairment event occurs and it is determined that the carrying value of the Trust s royalty interests may not be recoverable, an impairment will be recognized as measured by the amount by which the carrying amount of the royalty interests exceeds the fair value of these assets, which would likely be measured by discounting projected cash flows. There was no impairment of the assets as of December 31, 2014 or 2015.

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Notes to Financial Statements (Continued)

4. Federal Income Taxes

For federal income tax purposes, the Trust constitutes a fixed investment trust which is taxed as a grantor trust. A grantor trust is not subject to tax at the trust level. The Unit Holders are considered to own the Trust s income and principal as though no trust were in existence. The income of the Trust is deemed to have been received or accrued by each Unit Holder at the time such income is received or accrued by the Trust rather than when distributed by the Trust.

The Trust is a widely held fixed investment trust (WHFIT) classified as a non-mortgage widely held fixed investment trust (NMWHFIT) for federal income tax purposes. The Trustee is the representative of the Trust that will provide tax information in accordance with the applicable U.S. Treasury Regulations governing the information reporting requirements of the Trust as a WHFIT and a NMWHFIT.

The Royalty constitutes an economic interest in oil and natural gas properties for federal income tax purposes. Unit Holders must report their share of the production revenues of the Trust as ordinary income from oil and natural gas royalties and are entitled to claim depletion with respect to such income. The Royalty is treated as a single property for depletion purposes. The Trust has on file technical advice memoranda confirming such tax treatment.

Sales of natural gas production from certain coal seam wells drilled prior to January 1, 1993, qualified for federal income tax credits under Section 29 (now Section 45K) of the Internal Revenue Code of 1986, as amended (the Code), through 2002 but not thereafter. Accordingly, under present law, the Trust s production and sale of natural gas from coal seam wells does not qualify for tax credit under Section 45K of the Code (the Section 45 Tax Credit). Congress has at various times since 2002 considered energy legislation, including provisions to reinstate the Section 45 Tax Credit in various ways and to various extents, but no legislation that would qualify the Trust s current production for such credit has been enacted. No prediction can be made as to what future tax legislation affecting Section 45K of the Code may be proposed or enacted or, if enacted, its impact, if any, on the Trust and the Unit Holders.

The classification of the Trust s income for purposes of the passive loss rules may be important to a Unit Holder. As a result of the Tax Reform Act of 1986, royalty income such as that derived through the Trust will generally be treated as portfolio income that may not be offset or reduced by passive losses.

Tax positions taken by the Trust related to the Trust s pass-through status and state tax positions have been reviewed, and the Trustee is of the opinion that material positions taken would more likely than not be sustained by examination. As of December 31, 2015, the Trust s tax years 2012 and thereafter remain subject to examination.

5. Certain Contracts

Natural gas produced from the Underlying Properties is processed at the: Chaco, Val Verde, Milagro, Ignacio or Kutz plants, all located in the San Juan Basin. All such natural gas, other than that processed at Kutz, is sold to Chevron USA, Inc. (Chevron) under a contract with Burlington dated April 1, 2015 that will terminate on March 31, 2016. Burlington has solicited requests for proposal for the purchase of the volumes covered by that contract beginning April 1, 2016.

Natural gas produced from the Underlying Properties and processed at Kutz was being sold under two separate contracts with EDF Trading North America, LLC (EDF) and New Mexico Gas Company, Inc. (NMGC). The NMGC contract for the sale of certain winter-only supplies of the Kutz natural gas is for a five-year term expiring March 31, 2017. Burlington s contract with EDF terminates on March 31, 2016, and Burlington has solicited requests for proposal for the purchase of those volumes beginning April 1, 2016.

Notes to Financial Statements (Continued)

All three of the current natural gas purchase contracts provide for (i) the delivery of such natural gas at various delivery points through their respective termination dates; and (ii) the sale of such natural gas at prices that fluctuate in accordance with published indices for natural gas sold in the San Juan Basin of northwestern New Mexico.

Burlington contracts with Williams Four Corners, LLC (WFC) and Enterprise Field Services, LLC (EFS) for the gathering and processing of virtually all of the natural gas produced from the Underlying Properties. Four new contracts were entered into with WFC, each of which is effective for a term of 15 years, which commenced April 1, 2010. Burlington has signed a similar agreement with EFS which was effective November 1, 2011 for a term of 15 years. Burlington has disclosed to the Trust a summary of that agreement which the Trust has reviewed with its consultants, subject to conditions of confidentiality.

The Trust is not a party to any of the purchase, gathering or processing contracts. As part of the 1996 settlement of litigation filed by the Trustee in 1992 against Burlington and Southland, the Trustee and Burlington established a formal protocol pursuant to which compliance auditors retained by the Trustee have access to Burlington s books and records.

6. Significant Customers

Information as to significant purchasers of oil and natural gas production attributable to the Trust s economic interests is included in Note 5 above.

7. Development Costs

Burlington s capital budget plans for the Underlying Properties are delivered to the Trustee at the beginning of each calendar year. The estimates are subject to change, based on, among other things, Burlington s actual capital requirements, the pace of regulatory approvals, the mix of projects and swings in the price of natural gas.

Both the estimated annual capital expenditures and the actual expenses reported by Burlington include amounts attributable to capital budgets for prior years because capital expenditures are deducted in calculating Royalty Income in the month they accrue and projects within a given year s budget often extend into subsequent years. Further, Burlington s accounting period for capital expenditures runs through November 30 of each calendar year, such that capital expenditures incurred in December of each year are accounted for as part of the following year s capital expenditures. In addition, with respect to wells not operated by Burlington, Burlington s share of capital expenditures may not be paid until the following year(s) after those expenses were incurred by the operator.

The budget for capital expenditures in 2015 for properties subject to the Trust s royalty interest was estimated at $14.0 million, of which approximately $6.8 million was to be attributable to the capital budgets for 2014 and prior years. Actual capital expenditures of approximately $12.8 million were included in calculating royalty income paid to the Trust in calendar year 2015, of which approximately $5.2 million related to projects budgeted for prior years.

The 2014 capital expenditure budget was estimated at $4.8 million, of which approximately $3.0 million was to be attributable to the capital budgets for 2013 and prior years. Actual capital expenses for 2014 were $6.5 million, of which approximately $1.8 million related to projects budgeted for prior years.

The estimate for Burlington s capital expenditures for 2013 was $28.5 million, of which approximately $5.0 million was expected to be attributable to the capital budgets for 2012 and prior years. Actual capital expenditures for 2013 were approximately $21.5 million, of which approximately $12.3 million related to projects budgeted for prior years.

Notes to Financial Statements (Continued)

8. Settlements and Litigation

Burlington Matter

On July 31, 2014, the Trustee filed a lawsuit (the 2014 Litigation) against Burlington in New Mexico State Court. The Trust asserts claims for breach of contract and breach of the implied covenant of good faith and fair dealing, and seeks a declaratory judgment arising out of a number of unresolved revenue and expense audit exceptions asserted by the Trust s auditors. More particularly, the Trust claims that Burlington failed to properly account for and pay net overriding royalty interests to the Trust with respect to oil and natural gas production from numerous properties in the San Juan Basin of northwestern New Mexico. The Trust seeks monetary relief (including actual and punitive damages, costs, expenses, interest and attorney fees) in excess of $12 million, along with specific performance of certain contractual obligations, declaratory relief and a judgment for other relief to which it may show itself to be justly entitled. Burlington has filed an answer and denies liability. The parties have commenced written discovery and depositions, and are working to schedule mediation. The case is currently set for non-jury trial in September 2016.

In addition, Burlington notified the Trust in March 2008 that the distribution for that month would be reduced by approximately $4.9 million. Burlington described this amount as the Trust s portion of what Burlington had paid to settle certain *qui tam* claims asserted by the government for the underpayment of royalties (the *Qui Tam* Settlement). The Trust has objected to Burlington s unilateral decision to deduct any amount of the *Qui Tam* Settlement paid by Burlington from the distributions payable to the Trust and formally complained of that action as part of the 2014 Litigation. The Trust argues that no part of the *Qui Tam* Settlement should have been allocated to the Trust because the claim that gave rise to the settlement was presented to Burlington for payment or otherwise known to Burlington prior to the effective date of a mutual release of all claims entered into by Burlington and the Trust in 1996 (the 1996 Settlement). In the alternative, the Trust contends that (a) those portions of the royalty underpayment claims involved in the *Qui Tam* Settlement that had accrued and existed as of the date of the 1996 Settlement, whether known or unknown, were released by the 1996 Settlement, or (b) even if Burlington s allocation of part of the *Qui Tam* Settlement was not barred by the mutual release in the 1996 Settlement, the amount allocated to the Trust by Burlington was improper and excessive.

Jicarilla Matter

Burlington has informed the Trust that pursuant to an Order to Perform issued by the Minerals Management Service, (MMS), dated June 10, 1998 (the MMS Order), the Jicarilla Apache Nation (the Jicarilla) alleged that in valuing production for royalty purposes one must perform (i) a major portion analysis, which calculates value on the highest price paid or offered for a major portion of the natural gas produced from the field where the leased lands are situated; and (ii) a dual accounting calculation, which computes royalties on the greater of (a) the value of natural gas prior to processing or (b) the combined value of processed residue natural gas and plant products plus the value of any condensate recovered downstream without processing. The MMS Order alleged that Burlington s dual accounting calculations on Native American leases were based on less than major portion prices. In 2000, Burlington and the Jicarilla entered into a settlement agreement resolving the issues associated with the dual accounting calculation. The major portion calculation issue remains outstanding. Burlington takes the position that a judgment or settlement could entitle Burlington to reimbursement from the Trust for past periods.

In 2007 Burlington obtained an Administrative Order from the Department of the Interior (the DOI) rejecting that portion of the MMS Order requiring Burlington to calculate and pay additional royalties based on the major portion price derived by the MMS. The Jicarilla filed suit solely against the DOI in the United States District Court for the District of Columbia (the DOI Case) seeking a declaration that the Administrative Order is unlawful and of no force and effect, as well as an injunction requiring enforcement of the underlying major portion orders that were rejected by the Assistant Secretary. In 2009, a summary judgment was entered by the

Notes to Financial Statements (Continued)

district court in the DOI Case upholding the Administrative Order and dismissing the Jicarilla s claims. The Jicarilla appealed to the U.S. Court of Appeals for the D.C. Circuit, which held that the 2007 Administrative Order dismissing the Jicarilla claims was arbitrary and capricious with respect to January 1984 through February 1988 production periods and remanded the matter to the DOI for further proceedings. While a judgment or settlement in the DOI Case could impact the Royalty Income of the Trust, Burlington has informed the Trust that it does not have sufficient information to estimate a range of loss for the Trust because the DOI has not provided a major portion calculation for the January 1984 to February 1988 time period as required by the Court of Appeals ruling. Burlington indicates that the situation will not be alleviated until the DOI provides Burlington with a new Order to Perform or similar notice, but that it cannot predict when or if the DOI will provide such information or notice. The Trust s consultants will continue to monitor development in this matter and analyze the appropriateness of the allocation, if any, by Burlington of any portion of any settlement or judgment in calculating the Royalty.

9. Supplemental Oil and Gas Reserve Information (Unaudited)

Proved Oil and Natural Gas Reserves

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

The following table presents a reconciliation of proved reserve quantities attributable to the Royalty from December 31, 2012 to December 31, 2015:

	Crude Oil and Condensate (MBbls)	Natural Gas (MMcf)
Reserves as of December 31, 2012	204	104,448
Revisions of previous estimates	(2)	7,437
Extensions, discoveries and other additions	10	2,764
Production	(18)	(10,131)
Reserves as of December 31, 2013	194	104,518
Revisions of previous estimates	105	29,096
Extensions, discoveries and other additions	7	2,437
Production	(30)	(15,303)
Reserves as of December 31, 2014	276	120,748
Revisions of previous estimates	(87)	(37,211)
Extensions, discoveries and other additions	-	-
Production	(19)	(7,964)
Reserves as of December 31, 2015	170	75,572

Notes to Financial Statements (Continued)

Standardized Measure of Discounted Future Net Cash Flows

The following is a summary of a standardized measure of discounted future net cash flows related to the Trust s total proved natural gas and oil reserve quantities. Information presented is based upon valuation of proved reserves by using discounted cash flows based upon average oil and gas prices during the 12-month period prior to the fiscal year-end, 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 and severance and ad valorem taxes, if any, and economic conditions, discounted at the required rate of 10%. As the Trust is not subject to taxation at the trust level, no provision for income taxes has been made in the following disclosure. Trust prices may differ from posted NYMEX prices due to differences in product quality and property location. The impact of changes in current prices on reserves could vary significantly from year to year. Accordingly, the information presented below should not be viewed as an estimate of the fair market value of the Trust s oil and natural gas reserves or the costs that would be incurred to acquire equivalent reserves. A market value determination would require the analysis of additional parameters.

		December 31,	
	2015	2014	2013
		(in thousands)	
Future cash inflows	$ 181,018	$ 591,819	$ 436,660
Future costs	18,102	59,182	41,355
Future net cash flows	$ 162,916	$ 532,637	$ 395,305
Discount of future net cash flows at 10%	(59,795)	(224,549)	(158,683)
Standardized measure of discounted future net cash flows	$ 103,121	$ 308,088	$ 236,622

Estimates of proved oil and natural gas reserves are by their nature imprecise. Estimates of future net revenue attributable to proved reserves are sensitive to the unpredictable prices of oil and natural gas and other variables. Accordingly, under the allocation method used to derive the Trust s quantity of proved reserves, changes in prices will result in changes in quantities of proved oil and natural gas reserves and estimated future net revenues.

The 2015, 2014 and 2013 changes in the standardized measure of discounted future net cash flows related to future Royalty Income from proved reserves are as follows:

	2015	2014	2013
		(in thousands)	
Balance, January 1	$ 308,088	$ 236,622	$ 213,565
Revisions of prior-year estimates, change in prices and other	(216,339)	103,179	33,445
Extensions, discoveries and other additions	-	6,133	6,298
Accretion of discount	30,809	23,662	21,357
Royalty Income	(19,437)	(61,508)	(38,043)
Balance, December 31	$ 103,121	$ 308,088	$ 236,622

Reserve quantities and revenues shown in the tables above for the Royalty were estimated from projections of reserves and revenues attributable to the combined Burlington and Trust interests. Reserve quantities attributable to the Royalty were derived from estimates by allocating to the Royalty a portion of the total net reserve quantities of the interests, based upon gross revenue less production taxes. Because the reserve quantities attributable to the Royalty are estimated using an allocation of the reserves, any changes in prices or costs will result in changes in the estimated reserve quantities allocated to the Royalty. Therefore, the reserve quantities estimated will vary if different future price and cost assumptions occur. The future net cash flows were determined without regard to future federal income tax credits, if any, available to production from coal seam wells.

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Notes to Financial Statements (Continued)

For 2015, $2.29 per Mcf of natural gas and $36.48 per Bbl of oil were used in determining future net revenue. These prices were based on a 12-month unweighted average of the first-day-of-the-month pricing of $2.59 per MMBtu of Henry Hub natural gas and $50.28 per Bbl of West Texas Intermediate oil. The downward revision in reserve quantities for 2015 is due primarily to lower natural gas prices as well as a reduction in Burlington s development plans, which results in an elimination of proved undeveloped reserves.

For 2014, $4.68 per Mcf of natural gas and $81.09 per Bbl of oil were used in determining future net revenue. These prices were based on a 12-month unweighted average of the first-day-of-the-month pricing of $4.35 per MMBtu of Henry Hub natural gas and $94.99 per Bbl of West Texas Intermediate oil. The upward revision in reserve quantities for 2014 is due primarily to higher natural gas prices and lower lease operating expense.

For 2013, $3.98 per Mcf of natural gas and $84.86 per Bbl of oil were used in determining future net revenue. These prices were based on a 12-month unweighted average of the first-day-of-the-month pricing of $3.67 per MMBtu of Henry Hub natural gas and $96.94 per Bbl of West Texas Intermediate oil. The upward revision in reserve quantities for 2013 is due primarily to higher natural gas prices.

10. Quarterly Schedule of Distributable Income (Unaudited)

The following is a summary of the unaudited quarterly schedule of distributable income for the two years ended December 31, 2015 (in thousands, except per unit amounts):

2015	**Royalty Income**	**Distributable Income**	**Distributable Income and Distribution Per Unit**
First Quarter	$ 7,345	$ 6,763	$ 0.145098
Second Quarter	2,264	1,416	0.030385
Third Quarter	5,415	5,013	0.107567
Fourth Quarter	4,413	3,808	0.081695
Total	$ 19,437	$ 17,000	$ 0.364745

2014	**Royalty Income**	**Distributable Income**	**Distributable Income and Distribution Per Unit**
First Quarter	$ 14,526	$ 14,090	$ 0.302300
Second Quarter	18,125	17,712	0.380019
Third Quarter	16,076	15,693	0.336690
Fourth Quarter	12,781	12,378	0.265578
Total	$ 61,508	$ 59,873	$ 1.284587

11. Commitments and Contingencies

Contingencies related to the Underlying Properties that are unfavorably resolved would generally be reflected by the Trust as reductions to future Royalty Income payments to the Trust with corresponding reductions to cash distributions to Unit holders. See Note 8. Settlements and Litigation for a discussion of pending litigation.

12. Subsequent Events

Because a prolonged decline in natural gas prices may reduce Royalty Income, the Trustee increased the amount of cash reserves since the end of 2015 by $150,000 as of February 29, 2016.

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ITEM 9. ***CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE***

None.

ITEM 9A. ***CONTROLS AND PROCEDURES***

The Trust maintains a system of disclosure controls and procedures that is designed to ensure that information required to be disclosed in the Trust s filings under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the SEC s rules and forms. Due to the pass-through nature of the Trust, Burlington is the primary source of the information disclosed in this Form 10-K and the other periodic reports filed by the Trust with the SEC. Consequently, the Trust s ability to timely disclose relevant information in its periodic reports is dependent upon Burlington s delivery of such information. Accordingly, the Trust maintains disclosure controls and procedures designed to ensure that Burlington accurately and timely accumulates and delivers such relevant information to the Trustee and those who participate in the preparation of the Trust s periodic reports to allow for the preparation of such periodic reports and any decisions regarding disclosure.

The Conveyance transferring the Royalty to the Trust obligates Burlington to provide the Trust with certain information, including information concerning calculations of net proceeds owed to the Trust. Pursuant to the settlement of litigation in 1996 between the Trust and Burlington, Burlington agreed to newer, more formal financial reporting and audit procedures as compared to those provided in the Conveyance.

In order to help ensure the accuracy and completeness of the information required to be disclosed in the Trust s periodic reports, the Trust engages independent public accountants, compliance auditors, marketing consultants, attorneys and petroleum engineers. These outside professionals advise the Trustee in its review and compilation of this information for inclusion in this Form 10-K and the other periodic reports provided by the Trust to the SEC.

The Trustee has evaluated the Trust s disclosure controls and procedures as of December 31, 2015 and has concluded that such disclosure controls and procedures are effective, at the reasonable assurance level (as such term is used in Rule 13a-15(f) of the Exchange Act), to ensure that material information related to the Trust is gathered on a timely basis to be included in the Trust s periodic reports. The Trustee has also concluded that its disclosure controls and procedures are effective to ensure that information required to be disclosed by the Trustee in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the timeframes specified in the SEC s rules and forms. In reaching its conclusions, the Trustee has considered the Trust s dependence on Burlington to deliver timely and accurate information to the Trust.

Additionally, during the quarter ended December 31, 2015, there were no changes in the Trust s internal control over financial reporting (as defined in Rule 13a-15(f) of the Exchange Act) that materially affected, or are reasonably likely to materially affect, the Trust s internal control over financial reporting. Because the Trust does not have, nor does the Indenture provide for, officers, a board of directors or an independent audit committee, the Trustee has reviewed neither the Trust s disclosure controls and procedures nor the Trust s internal control over financial reporting in concert with management, a board of directors or an independent audit committee.

Trustee s Report on Internal Control over Financial Reporting

Compass Bank, in its capacity as trustee of the Trust, is responsible for establishing and maintaining adequate internal control over financial reporting. The Trust s internal control over financial reporting is a process designed under the supervision of the Trustee to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Trust s financial statements for external purposes in accordance with a modified cash basis of accounting, which is a comprehensive basis of accounting other than U.S. generally accepted accounting principles.

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As of December 31, 2015, the Trustee assessed the effectiveness of the Trust s internal control over financial reporting based on the criteria for effective internal control over financial reporting established in *Internal Control Integrated Framework* , issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 Framework). Based on the assessment, the Trustee determined that the Trust maintained effective internal control over financial reporting as of December 31, 2015, based on those criteria.

Weaver and Tidwell, L.L.P., the independent registered public accounting firm that audited the financial statements of the Trust included in this Annual Report on Form 10-K, has issued an attestation report on the Trust s internal control over financial reporting as of December 31, 2015. The report, which expresses an unqualified opinion on the effectiveness of the Trust s internal control over financial reporting as of December 31, 2015, is included in this Item under the heading Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting.

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Report of Independent Registered Public

Accounting Firm on Internal Control over Financial Reporting

Compass Bank, Trustee

San Juan Basin Royalty Trust

We have audited San Juan Basin Royalty Trust s (the Trust) internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Compass Bank (the Trustee) is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the Trustee s Report on Internal Control over Financial Reporting in Item 9A. Our responsibility is to express an opinion on the Trust s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A trust s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the Trust s modified cash basis of accounting, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America. A trust s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the trust; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with its modified cash basis of accounting, and that receipts and expenditures of the trust are being made only in accordance with authorizations of the trustee; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the trust s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the COSO criteria.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the statements of assets, liabilities, and trust corpus as of December 31, 2015 and 2014 and the related statements of distributable income and changes in trust corpus of the San Juan Basin Royalty Trust for each of the three years in the period ended December 31, 2015, and our report dated February 29, 2016 expressed an unqualified opinion thereon.

WEAVER AND TIDWELL, L.L.P.

Fort Worth, Texas

February 29, 2016

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ITEM 9B. ***OTHER INFORMATION***

None.

PART III

ITEM 10. ***DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT***

The Trust is managed by a corporate trustee and has no directors, executive officers or employees. Accordingly, the Trust does not have an audit committee, audit committee financial expert, nominating committee or a code of ethics applicable to executive officers. The Trustee has adopted a policy regarding standards of conduct and conflicts of interest applicable to all directors, officers and employees of the Trustee. The Trustee is a corporate trustee which may be removed, with or without cause, at a meeting of the Unit Holders, by the affirmative vote of the holders of a majority of all the Units then outstanding.

Section 16(a) Beneficial Ownership Reporting Compliance

The Trust has no directors or officers. Accordingly, only holders of more than 10% of the Trust s Units are required to file with the SEC initial reports of ownership of Units and reports of changes in such ownership. Based solely on a review of these reports, the Trust believes that the applicable reporting requirements of Section 16(a) of the Exchange Act were complied with for all transactions which occurred in 2015.

ITEM 11. ***EXECUTIVE COMPENSATION***

The Trust has no directors, executive officers or employees to whom it pays compensation. The Trust is administered by employees of the Trustee in the ordinary course of their employment who receive no compensation specifically related to their services to the Trust. Accordingly, the Trust does not have a compensation committee or maintain any equity compensation plans, and there are no Units reserved for issuance under any such plans.

ITEM 12. ***SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED SECURITY HOLDER MATTERS***

The Trust has no directors, executive officers or employees. Accordingly, the Trust does not maintain any equity compensation plans and there are no Units reserved for issuance under any such plans.

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Security Ownership of Certain Beneficial Owners

The following table sets forth as of February 5, 2016 information with respect to the Unit Holders who were known to the Trustee to be the beneficial owners of more than 5 percent of the outstanding Units.

Name and Address of Beneficial Owner	Number of Units Beneficially Owned	Percent
First Eagle Investment Management, LLC 1345 Avenue of the Americas New York, NY 10105[(1)]	5,444,968	11.68%
Seymour Schulich 20 Eglinton Avenue West, Suite 1900 Toronto ON, Canada M4R 1K8[(2)]	3,600,000	7.29%
Beck, Mack & Oliver LLC 360 Madison Avenue New York, NY 10017[(3)]	2,585,335	5.55%

(1) This information was provided in a Schedule 13G/A filed with the SEC on February 5, 2016 by First Eagle Investment Management, LLC, and which stated First Eagle Investment Management, LLC beneficially holds such Units on behalf of its investment advisory clients and is deemed to have sole voting power with respect to 5,323,031 of the Units and sole power to dispose or to direct the disposition of 5,444,968 of the Units. The First Eagle Global Fund, a registered investment Company for which First Eagle Investment Management, LLC acts as investment adviser, may be deemed to beneficially own 3,908,035 of these 5,444,968 units, or 8.38% of the outstanding Units.

(2) This information was provided to the SEC and to the Trustee in a Schedule 13G filed with the SEC on January 7, 2015, on behalf of Seymour Schulich.

(3) This information was provided in a Schedule 13G/A filed with the SEC on February 1, 2016 by Beck, Mack & Oliver LLC, and which stated Beck, Mack & Oliver LLC beneficially holds such units on behalf of its investment advisory clients and is deemed to have sole voting power with respect to 2,496,301 of the Units and shared power to dispose or to direct the disposition of 2,585,335 of the Units.

Security Ownership of Trustee

Compass Bank serves as agent and custodian for certain customer accounts. As of February 5, 2016, Compass Bank could be deemed to beneficially own 27,012 Units related to these accounts, or less than one percent of the outstanding Units. Compass Bank has sole voting power over 5,000 of these Units and no voting power over the remaining 22,012, and has sole power to dispose of 5,000 of such Units. Compass Bank does not have a pecuniary interest in any of these Units.

Changes in Control

The Trustee knows of no arrangement, including any pledge by any person of Units of the Trust, the operation of which may at a subsequent date result in a change of control of the Trust.

ITEM 13. ***CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE***

The Trust has no directors or executive officers, therefore no determination been made relative to director independence. See Item 11 for the remuneration received by the Trustee during the year ended December 31, 2015 and Item 12 for information concerning Units owned by the Trustee.

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ITEM 14. *PRINCIPAL ACCOUNTANT FEES AND SERVICES*

The following table presents fees for professional audit services rendered by Weaver and Tidwell, L.L.P., the Trust s principal accountants, for the audit of the Trust s annual financial statements for the fiscal years ended December 31, 2015 and 2014 and fees billed for other services rendered to the Trust by Weaver and Tidwell, L.L.P. during those periods.

	2015	2014
Audit Fees	$ 90,140	$ 87,160
Audit-Related Fees	-	-0-
Tax Fees	4,660	4,040
All Other Fees	-	-0-
Total	$ 94,800	$ 91,200

Audit Fees consist of fees billed for professional services rendered for the audit of the Trust s annual financial statements and internal control over financial reporting, review of the interim financial statements included in the Trust s quarterly reports and services that are normally provided by Weaver and Tidwell, L.L.P. in connection with statutory and regulatory filings or engagements.

Audit-Related Fees consist of fees billed for assurance and related services that are reasonably related to the performance of the audit or review of the Trust s financial statements. This category includes fees related to audit and attest services not required by statute or regulations and consultations concerning financial accounting and reporting standards.

Tax Fees consist of fees for professional services billed for tax compliance, tax advice and tax planning. These services include assistance regarding federal and state tax compliance, return preparation, preparation of the B-schedules and tax booklet.

All Other Fees consist of fees billed for products and services other than the services reported above.

The Trust has no directors or executive officers. Accordingly, the Trust does not have an audit committee and there are no audit committee pre-approval policies or procedures relating to services provided by the Trust s independent accountants. Pursuant to the terms of the Indenture, the Trustee engages and approves all services rendered by the Trust s independent accountants.

PART IV

ITEM 15. *EXHIBITS AND FINANCIAL STATEMENT SCHEDULES*

The following documents are filed as a part of this Annual Report on Form 10-K:

Financial Statements

Included in Part II of this Annual Report on Form 10-K:

Report of Independent Registered Public Accounting Firm

Statements of Assets, Liabilities and Trust Corpus

Statements of Distributable Income

Statements of Changes in Trust Corpus

Notes to Financial Statements

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Financial Statement Schedules

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

Exhibits

Exhibit Number	Description
4(a)	San Juan Basin Amended and Restated Royalty Trust Indenture, dated December 12, 2007, filed as Exhibit 99.2 to the Trust s Current Report on Form 8-K filed with the SEC on December 14, 2007, and incorporated herein by reference.*
4(b)	Net Overriding Royalty Conveyance from Southland Royalty Company to The Fort Worth National Bank, as Trustee, dated November 3, 1980 (without Schedules), filed as Exhibit 4(b) to the Trust s Annual Report on Form 10-K filed with the SEC for the year ended December 31, 2006, incorporated herein by reference.*
4(c)	Assignment of Net Overriding Interest (San Juan Basin Royalty Trust), dated September 30, 2002, between Bank One, N.A. and TexasBank, filed as Exhibit 4(c) to the Trust s Quarterly Report on Form 10-Q filed with the SEC for the quarter ended September 30, 2002, incorporated herein by reference.*
23	Consent of Cawley, Gillespie & Associates, Inc., reservoir engineer.**
31	Certification required by Rule 13a-14(a), dated February 29, 2016, by Joshua R. Peterson, Vice President and Senior Trust Officer of Compass Bank, the Trustee of the Trust.**
32	Certification required by Rule 13a-14(b), dated February 29, 2016, by Joshua R. Peterson, Vice President and Senior Trust Officer of Compass Bank, on behalf of Compass Bank, the Trustee of the Trust.***
99.1	Independent Petroleum Engineers Report prepared by Cawley, Gillespie & Associates, Inc., dated February 29, 2016.**

* A copy of this Exhibit is available to any Unit Holder (free of charge) upon written request to the Trustee, Compass Bank, 300 W. 7th St., Suite B, Fort Worth, Texas 76102.

** Filed herewith.

*** Furnished herewith.

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SIGNATURE

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.

SAN JUAN BASIN ROYALTY TRUST

By: COMPASS BANK, AS TRUSTEE OF THE SAN JUAN BASIN ROYALTY TRUST

By: /s/ Joshua R. Peterson
Joshua R. Peterson
Vice President and Senior Trust Officer

Date: February 29, 2016

(The Trust has no directors or executive officers)

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EXHIBIT INDEX

Exhibit Number	Description
4(a)	San Juan Basin Amended and Restated Royalty Trust Indenture, dated December 12, 2007 (the original Royalty Trust Indenture, dated November 1, 1980 having been entered into between Southland Royalty Company and The Fort Worth National Bank, as Trustee, which was amended and restated effective September 30, 2002), heretofore filed as Exhibit 99.2 to the Trust s Current Report on Form 8-K filed with the SEC on December 14, 2007, is incorporated herein by reference.*
4(b)	Net Overriding Royalty Conveyance from Southland Royalty Company to The Fort Worth National Bank, as Trustee, dated November 3, 1980 (without Schedules), heretofore filed as Exhibit 4(b) to the Trust s Annual Report on Form 10-K filed with the SEC on March 1, 2007, is incorporated herein by reference.*
4(c)	Assignment of Net Overriding Interest (San Juan Basin Royalty Trust), dated September 30, 2002, between Bank One, N.A. and TexasBank, heretofore filed as Exhibit 4(c) to the Trust s Quarterly Report on Form 10-Q filed with the SEC for the quarter ended September 30, 2002, is incorporated herein by reference.*
10	Indemnification Agreement, dated May 13, 2003, with effectiveness as of July 30, 2002, by and between Lee Ann Anderson and San Juan Basin Royalty Trust, heretofore filed as Exhibit 10(a) to the Trust s Quarterly Report on Form 10-Q filed with the SEC for the quarter ended March 31, 2003, is incorporated herein by reference.*
23	Consent of Cawley, Gillespie & Associates, Inc., reservoir engineer.**
31	Certification required by Rule 13a-14(a), dated February 29, 2016, by Joshua R. Peterson, Vice President and Senior Trust Officer of Compass Bank, the Trustee of the Trust.**
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