TORTOISE ENERGY INDEPENDENCE FUND, INC.
Form N-Q
April 29, 2015

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

FORM N-Q
QUARTERLY SCHEDULE OF PORTFOLIO HOLDINGS OF REGISTERED MANAGEMENT INVESTMENT COMPANY

Investment Company Act file number 811-22690

Tortoise Energy Independence Fund, Inc.
(Exact name of registrant as specified in charter)

11550 Ash Street, Suite 300, Leawood, KS 66211
(Address of principal executive offices) (Zip code)

Terry Matlack
Diane Bono
11550 Ash Street, Suite 300, Leawood, KS 66211

(Name and address of agent for service)

913-981-1020
Registrant's telephone number, including area code

Date of fiscal year end: November 30

Date of reporting period: February 28, 2015

Item 1. Schedule of Investments.

Tortoise Energy Independence Fund, Inc.
SCHEDULE OF INVESTMENTS (Unaudited)

	February 28, 2015		
	Shares		Fair Value
Common Stock - 89.4%(1)			
Crude/Refined Products Pipelines - 0.8%(1)			
United States - 0.8%(1)			
Plains GP Holdings, L.P.	91,716	$	2,626,746
Natural Gas/Natural Gas Liquids Pipelines - 0.0%(1)			
United States - 0.0%(1)			
Kinder Morgan, Inc.	2		82
Oil and Gas Production - 88.6%(1)			
Canada - 8.1%(1)			
ARC Resources LTD.	334,600		6,463,955
Cenovus Energy Inc.	153,200		2,648,828
Enerplus Corporation	275,800		2,791,096
Penn West Petroleum Ltd.	6,400		12,928
Suncor Energy Inc.(2)(3)	465,600		14,014,560
The Netherlands - 2.3%(1)			
Royal Dutch Shell plc (ADR)	114,500		7,484,865
United Kingdom - 1.3%(1)			
BP p.l.c. (ADR)	96,400		3,994,816
United States - 76.9%(1)			
Anadarko Petroleum Corporation(2)(3)	330,900		27,871,707
Antero Resources Corporation(2)(3)(4)	150,610		5,941,564
Cabot Oil & Gas Corporation(2)(3)	151,700		4,399,300
Carrizo Oil & Gas, Inc.(2)(3)(4)	198,000		9,422,820
Chesapeake Energy Corporation(2)(3)	436,900		7,287,492
Cimarex Energy Co.(2)(3)	89,173		9,780,495
Concho Resources Inc.(2)(3)(4)	116,143		12,650,296
Continental Resources, Inc.(2)(3)(4)	135,900		6,046,191
Devon Energy Corporation(2)(3)	120,800		7,440,072
Energen Corporation(2)(3)	76,700		4,957,888
EOG Resources, Inc.(2)(3)	363,300		32,595,276
EP Energy Corporation (4)	142,700		1,605,375
EQT Corporation(2)(3)	238,006		18,995,259
Hess Corporation(2)(3)	33,793		2,537,178
Laredo Petroleum, Inc.(4)	194,540		2,320,862
Marathon Oil Corporation(2)(3)	459,100		12,790,526
Newfield Exploration Company(2)(3)(4)	276,088		9,119,187
Noble Energy, Inc.(2)(3)	205,000		9,682,150
Occidental Petroleum Corporation(2)(3)	192,100		14,960,748
Pioneer Natural Resources Company(2)(3)	186,215		28,401,512
Range Resources Corporation(2)(3)	224,200		11,106,868
RSP Permian, Inc.(4)	110,556		3,002,701
Whiting Petroleum Corporation(2)(3)(4)	115,227		3,898,129

			284,224,644
Total Common Stock (Cost $321,074,540)			286,851,472
Master Limited Partnerships and Related Companies - 30.0%(1)			
Crude/Refined Products Pipelines - 18.8%(1)			
United States - 18.8%(1)			
Buckeye Partners, L.P.	49,673		3,861,579
Enbridge Energy Management, L.L.C.(5)	455,116		16,966,719
Magellan Midstream Partners, L.P.	92,000		7,562,400
MPLX LP	117,232		9,636,470
Phillips 66 Partners LP	65,900		4,691,421
Plains All American Pipeline, L.P.	179,229		8,941,735
Rose Rock Midstream, L.P.	32,489		1,506,840
Shell Midstream Partners, L.P.	30,756		1,201,329
Tesoro Logistics LP	77,377		4,442,987
Valero Energy Partners LP	26,106		1,391,189
			60,202,669
Natural Gas/Natural Gas Liquids Pipelines - 4.1%(1)			
United States - 4.1%(1)			
Columbia Pipeline Partners LP	35,719		989,059
Energy Transfer Partners, L.P.	77,700		4,621,596
Enterprise Products Partners L.P.	229,988		7,667,800
			13,278,455
Natural Gas Gathering/Processing - 7.1%(1)			
United States - 7.1%(1)			
Antero Midstream Partners LP	38,218		993,668
DCP Midstream Partners, LP	94,524		3,762,055
EnLink Midstream Partners, LP	86,700		2,328,762
Regency Energy Partners LP	182,456		4,450,102
Targa Resources Partners LP	95,800	•increase the power of the Trustee to engage in business or investment activities;	

•decrease the incentive threshold or increase the subordination threshold or change the portion of the quarterly cash distributions payable as an incentive distribution;

•alter the rights of the Trust unitholders as among themselves; or

•permit the Trustee to distribute the Royalty Interests in kind.

Amendments to the trust agreement's provisions addressing the following matters may not be made without Avalon's consent:

•dispositions of the Trust's assets;

- indemnification of the Trustee;
- reimbursement of out-of-pocket expenses of Avalon when acting as the Trust's agent;
- termination of the Trust; and
- amendments of the trust agreement.

3

Certain amendments to the trust agreement do not require the vote of the Trust unitholders. See “Permitted Amendments” below.

The business and affairs of the Trust are managed by the Trustee. The Trustee has no ability to manage or influence the operations of the Underlying Properties. Avalon operates the Underlying Properties, but has no ability to manage or influence the management of the Trust, except through its limited voting rights as a holder of Trust units.

Duties and Powers of the Trustee. The duties and powers of the Trustee are specified in the trust agreement and by the laws of the State of Delaware, except as modified by the trust agreement. The trust agreement provides that the Trustee does not have any duties or liabilities, including fiduciary duties, except as expressly set forth in the trust agreement, and the duties and liabilities of the Trustee as set forth in the trust agreement replace any other duties and liabilities, including fiduciary duties, to which the Trustee might otherwise be subject.

The Trustee’s principal duties consist of:

•collecting cash proceeds attributable to the Royalty Interests;

•paying expenses, charges and obligations of the Trust from the Trust’s assets;

•making cash distributions to the Trust unitholders in accordance with the trust agreement;

•causing to be prepared and distributed a Schedule K-1 for each Trust unitholder and preparing and filing tax returns on behalf of the Trust; and

•causing to be prepared and filed reports required to be filed under the Exchange Act and under the rules of any securities exchange or quotation system on which the Trust units are listed or admitted to trading.

Avalon provides, and SandRidge provided prior to the Sale Transaction, administrative and other services to the Trust in fulfillment of certain of the foregoing duties, pursuant to the terms of the administrative services agreement. SandRidge performs these services on behalf of, and in conjunction with, Avalon pursuant to the terms of the transition services agreement, which terminates on March 31, 2019 unless otherwise extended by the parties.

Except as set forth below, cash held by the Trustee as a reserve against future liabilities must be invested in:

•interest-bearing obligations of the United States government;

•money market funds that invest only in United States government securities;

•repurchase agreements secured by interest-bearing obligations of the United States government; or

•bank certificates of deposit.

Alternatively, cash held for distribution at the next distribution date may be held in a non-interest-bearing account.

The Trust may not acquire any asset except the Royalty Interests and cash and temporary cash investments, and it may not engage in any investment activity except investing cash on hand.

The trust agreement provides that the Trustee will not make business decisions affecting the assets of the Trust. However, the Trustee may:

•prosecute or defend, and settle, claims of or against the Trust or its agents;

•retain professionals and other third parties to provide services to the Trust;

•charge for its services as Trustee;

•retain funds to pay for future expenses and deposit them with one or more banks or financial institutions (which may include the Trustee to the extent permitted by law);

4

•lend funds at commercial rates to the Trust to pay the Trust's expenses; and

•seek reimbursement from the Trust for its out-of-pocket expenses.

In discharging its duty to Trust unitholders, the Trustee may act in its discretion and will be liable to the Trust unitholders only for willful misconduct, bad faith or gross negligence. The Trustee will not be liable for any act or omission of its agents or employees unless the Trustee acted with willful misconduct, bad faith or gross negligence in its selection and retention of such agents or employees. The Trustee will be indemnified individually or as the Trustee for any liability or cost that it incurs in the administration of the Trust, except in cases of willful misconduct, bad faith or gross negligence. The Trustee has a lien on the assets of the Trust as security for this indemnification and its compensation earned as Trustee. Trust unitholders will not be liable to the Trustee for any indemnification. The Trustee ensures that all contractual liabilities of the Trust are limited to the assets of the Trust. The Trustee has not loaned and does not intend to lend funds to the Trust.

Merger or Consolidation of Trust. The Trust may merge or consolidate with or into, or convert into, one or more limited partnerships, general partnerships, corporations, business trusts, limited liability companies, or associations or unincorporated businesses if such transaction is agreed to by the Trustee and approved by the vote of the holders of (i) a majority of the Trust units (excluding Trust units owned by Avalon) and (ii) a majority of the Trust units (including Trust units owned by Avalon), in each case voting in person or by proxy at a meeting of such holders at which a quorum is present and such transaction is permitted under the Delaware Statutory Trust Act and any other applicable law. At any time that Avalon owns less than 10% of the total Trust units outstanding, however, the standard for approval will be the vote of the holders of a majority of the Trust units, including Trust units owned by Avalon, voting in person or by proxy at a meeting of such holders at which a quorum is present..

Trustee's Power to Sell Royalty Interests. The Trustee may sell the Royalty Interests under any of the following circumstances:

•the sale is requested by Avalon in accordance with the provisions of the trust agreement; or

•the sale is approved by the vote of the holders of (i) a majority of the Trust units (excluding Trust units owned by Avalon) and (ii) a majority of the Trust units (including Trust units owned by Avalon), in each case voting in person or by proxy at a meeting of such holders at which a quorum is present; except that at any time that Avalon owns less than 10% of the total Trust units outstanding, the standard for approval will be the vote of the holders of a majority of the Trust units, including Trust units owned by Avalon, voting in person or by proxy at a meeting of such holders at which a quorum is present.

Upon dissolution of the Trust, the Trustee must sell the Royalty Interests. No Trust unitholder approval is required in this event.

The Trustee will distribute the net proceeds from any sale of the Royalty Interests and other assets to the Trust unitholders after payment or reasonable provision for payment of the liabilities of the Trust.

Permitted Amendments. The Trustee may amend or supplement the trust agreement, the conveyances, the administrative services agreement, or the registration rights agreement, without the approval of the Trust unitholders, to cure ambiguities, to correct or supplement defective or inconsistent provisions, to grant any benefit to all Trust unitholders, to evidence or implement any changes required by applicable law or to change the name of the Trust, provided, however, that any such supplement or amendment does not adversely affect the interests of the Trust unitholders. Furthermore, the Trustee, acting alone, may amend the administrative services agreement without the approval of Trust unitholders if such amendment would not increase the cost or expense of the Trust or create an adverse economic impact on the Trust unitholders.

All other permitted amendments to the trust agreement and other agreements listed above may only be made by the vote of the holders of (i) a majority of the Trust units (excluding Trust units owned by Avalon) and (ii) a majority of the Trust units (including Trust units owned by Avalon), in each case voting in person or by proxy at a meeting of such holders at which a quorum is present; except that at any time that Avalon owns less than 10% of the total Trust units outstanding, the standard for approval will be the vote of the holders of a majority of the Trust units, including Trust units owned by Avalon, voting in person or by proxy at a meeting of such holders at which a quorum is present. Abstentions and broker non-votes will not be deemed to be a vote cast.

5

Miscellaneous. The Trustee may consult with legal counsel (which may include legal counsel to Avalon), accountants, tax advisors, geologists and engineers and other parties the Trustee believes to be qualified as experts on the matters for which advice is sought. The Trustee will be protected for any action it takes in good faith reliance upon the opinion of an expert.

The Delaware Trustee and the Trustee may resign at any time or be removed with or without cause at any time by the vote of the holders of a majority of the Trust units (excluding Trust units owned by Avalon), voting in person or by proxy at a meeting of such holders at which a quorum is present; except that at any time that Avalon owns less than 10% of the outstanding Trust units, the standard for approval will be the vote of the holders of a majority of the Trust units, including Trust units owned by Avalon, voting in person or by proxy at a meeting of such holders at which a quorum is present. Abstentions and broker non-votes will not be deemed to be a vote cast. Any successor must be a bank or trust company meeting certain requirements including having combined capital, surplus and undivided profits of at least $20 million, in the case of the Delaware Trustee, and $100 million, in the case of the Trustee.

Distributions

The Trust makes quarterly cash distributions of substantially all of its cash receipts, after deducting amounts for the Trust’s administrative expenses, property tax and Texas franchise tax, and cash reserves withheld by the Trustee, on or about the 60th day following the completion of each quarter. Each distribution covers production for a three-month period. The amount of Trust revenues and cash distributions to Trust unitholders depends on:

•oil, natural gas and NGL prices received;

•volume of oil, natural gas and NGL produced and sold;

•post-production costs (which includes internal costs and third person costs incurred by SandRidge and/or Avalon) and any applicable taxes; and

•the Trust’s general and administrative expenses.

The amount of the quarterly distributions will fluctuate from quarter to quarter, depending on the factors discussed above. There is no minimum required distribution. See Note 4 to the financial statements contained in Item 8 of this report for further discussion of Trust distributions.

If at any time the Trust’s cash on hand (including available cash reserves) is not sufficient to pay the Trust’s ordinary course administrative expenses as they become due, the Trust may borrow funds from the Trustee or other lenders, including Avalon, to pay such expenses. The Trustee has not loaned and does not intend to lend funds to the Trust. If such funds are borrowed, no further distributions will be made to Trust unitholders (except in respect of any previously determined quarterly distribution amount) until the borrowed funds have been repaid.

The Trust Agreement provides that, if at any time the Trust’s cash on hand (including available cash reserves) is not sufficient to pay the Trust’s ordinary course administrative expenses as they become due, Avalon (as assignee of SandRidge) will, at the Trustee’s request, loan funds to the Trust necessary to pay such expenses. Any such loan will be on an unsecured basis, and the terms of such loan will be substantially the same as those which would be obtained in an arms’ length transaction between Avalon and an unaffiliated third party. If Avalon provides such funds to the Trust, Avalon may permit the Trust to make distributions prior to Avalon being repaid for such loan. In addition, Avalon would become a creditor of the Trust and its interest as a creditor could conflict with the interests of other Trust unitholders. To date, the Trust has not borrowed funds from either SandRidge or Avalon.

Properties

As of December 31, 2018, 2017 and 2016, the Trust's properties consisted of Royalty Interests in (a) the Initial Wells and (b) 856 additional wells (equivalent to 888 Trust Development Wells under the development agreement) that were drilled and perforated for completion between April 1, 2011 and December 31, 2014. SandRidge was credited for having drilled one full Trust Development Well if a well was drilled and perforated for completion to the Grayburg/San Andres formation and SandRidge's net revenue interest in the well was equal to 69.3%. For wells in which SandRidge had a net revenue interest equal to or greater than 69.3%, SandRidge received proportionate credit for such well. The Royalty Interests are in properties located in the greater Fuhrman-Mascho field, a field in Andrews County, Texas that produces primarily oil from the Grayburg/San Andres formation in the Permian Basin.

Proved Reserves. The following estimates of net proved oil, natural gas and NGL reserves are based on reserve reports prepared by Netherland, Sewell & Associates, Inc. (“Netherland Sewell”), independent petroleum engineers. The PV-10 and Standardized Measure shown in the table below are not intended to represent the current value of estimated oil, natural gas and NGL reserves attributable to the Royalty Interests as of the dates shown. The reserve reports as of December 31, 2018, 2017 and 2016 were based on the average price during the 12-month periods ended December 31, 2018, 2017 and 2016, using first-day-of-the-month prices for each month. Refer to “Risk Factors” in Item 1A of this report and “Trustee’s Discussion and Analysis of Financial Condition and Results of Operations” in Item 7 of this report in evaluating the reserve information presented below.

Avalon provides, and SandRidge provided prior to the Sale Transaction, certain services respecting the estimation of net proved oil, natural gas and NGL reserves to the Trust pursuant to the terms of the administrative services agreement. SandRidge performs these services on behalf of, and in conjunction with, Avalon pursuant to the terms of the transition services agreement, which terminates on March 31, 2019 unless otherwise extended by the parties. Consistent with past practice, the process begins with a SandRidge staff reservoir engineer collecting and verifying all pertinent data, including but not limited to well test data, production data, historical pricing, cost information, property ownership interests, reservoir data, and geosciences data. This data was reviewed by members of SandRidge’s Reservoir Engineering Department and various levels of SandRidge management, together with representatives of Avalon, for accuracy, before consultation with the independent petroleum engineers. Members of SandRidge’s Reservoir Engineering Department consulted regularly with the independent petroleum engineers and Avalon employees during the reserve estimation process to review properties, assumptions, and any new data available. The internal reserve estimates completed and methodologies used by SandRidge on behalf of, an in conjuction with, Avalon were compared to the independent petroleum engineers’ estimates and conclusions before the reserve estimates were included in the independent petroleum engineers’ reports. Additionally, members of both SandRidge’s and Avalon’s senior management reviewed and approved the reserve reports contained herein.

Internal Controls. SandRidge’s Senior Vice President - Reserves, Technology and Business Development is the technical person primarily responsible for overseeing the preparation of the Trust’s reserve estimates on behalf of the Trustee and, beginning effective November 1, 2018, on behalf of, and in conjunction with, Avalon, pursuant to the transition services agreement. He has a Bachelor of Science degree in Petroleum Engineering with over 30 years of practical industry experience, including over 30 years of estimating and evaluating reserve information. In addition, he has also been a certified professional engineer in the State of Oklahoma since 2007 and a member of the Society of Petroleum Engineers since 1980.

SandRidge’s Reservoir Engineering Department, on behalf of, and in conjunction with, Avalon continually monitors asset performance, making reserves estimate adjustments, as necessary, to ensure the most current reservoir information is reflected in reserves estimates. Reserve information includes production histories as well as other geologic, economic, ownership and engineering data. The Reservoir Engineering Department currently has a total of six full-time employees, consisting of four degreed engineers and two engineering and business analysts with a minimum of a four-year degree in mathematics, finance or other business or science field. SandRidge maintains a continuous education program for engineers and analysts on new technologies and industry advancements and also offers refresher training on basic skill sets.

In order to ensure the reliability of reserves estimates, SandRidge’s internal controls observed within the reserve estimation process included:

•No employee’s compensation is tied to the amount of reserves booked.

•Reserves estimates are prepared by experienced reservoir engineers or under their direct supervision.

•The Senior Vice President - Reserves, Technology and Business Development reports directly to SandRidge's Chief Operating Officer.

•The Reservoir Engineering Department follows comprehensive SEC-compliant internal policies to determine and report proved reserves including:

•confirming that reserve estimates include all applicable properties and are based upon proper working and net revenue interests;

•reviewing and using in the estimation process data provided by other departments within SandRidge such as Accounting; and

•comparing and reconciling internally generated reserve estimates to those prepared by third parties.

The independent petroleum engineers estimated all of the proved reserve information in these reports in accordance with the definitions and guidelines of the SEC and in conformity with the Accounting Standards Codification Topic 932, Extractive Activities-Oil and Gas. Neither Netherland Sewell nor any member of the SandRidge Reservoir Engineering Department or employee of Avalon own an interest in any of the Underlying Properties, nor are they employed on a contingent basis. The qualifications of Netherland Sewell’s technical personnel primarily responsible for overseeing the preparation of the Trust’s reserves estimates included in this report include the following:

•practicing consulting petroleum engineering since 2013 and over 14 years of prior industry experience;

•licensed professional engineers in the State of Texas; and

•a Bachelor of Science Degree in Chemical Engineering.

These qualifications meet or exceed the Society of Petroleum Engineers’ standard requirements to be a professionally qualified Reserve Estimator and Auditor.

Reporting of Natural Gas Liquids. Natural gas liquids, or NGL, are produced as a result of the processing of a portion of the Trust’s natural gas production stream. At December 31, 2018, NGL constituted approximately 12% of the Trust’s total proved reserves on a barrel equivalent basis and represented volumes to be produced from properties where contracts are in place for the extraction and separate sale of NGL. NGL are products sold by the gallon. In reporting proved reserves and production of NGL, production and reserves have been included in barrels. The extraction of NGL in the processing of natural gas reduces the volume of natural gas available for sale. All production information related to natural gas is reported net of the effect of any reduction in natural gas volumes resulting from the processing and extraction of NGL.

A summary of the Trust’s proved oil, natural gas and NGL reserves, all of which are located in the State of Texas, is presented below:

	December 31,		
Estimated Proved Reserves(1)	2018	2017	2016
Developed			
Oil (MBbls)	4,567.5	4,999.9	5,075.2
NGL (MBbls)	691.8	758.9	734.6
Natural gas (MMcf)	2,163.8	2,544.4	2,417.5
Total proved developed (MBoe)(2)	5,619.9	6,182.9	6,212.8
Undeveloped			
Oil (MBbls)	—	—	—
NGL (MBbls)	—	—	—
Natural gas (MMcf)	—	—	—
Total proved undeveloped (MBoe)(2)	—	—	—
Total Proved			
Oil (MBbls)	4,567.5	4,999.9	5,075.2
NGL (MBbls)	691.8	758.9	734.6

Natural gas (MMcf)	2,163.8	2,544.4	2,417.5
Total proved (MBoe)(2)	5,619.9	6,182.9	6,212.8
PV-10 (in millions)(3)(4)	$ 135.7	$ 123.2	$ 109.9
Standardized Measure of Discounted Net Cash Flows (in millions)(4)	$ 135.5	$ 123.0	$ 109.6

(1) Determined using a 12-month average of the first-day-of-the-month index price without giving effect to derivative transactions. The prices used in the reserve report yield weighted average wellhead prices, which are based on first-day-of-the-month index prices and adjusted for transportation and regional price differentials. The index prices and the equivalent weighted average wellhead prices are shown in the table below.

8

	Weighted average wellhead prices			Index prices	
	Oil (per Bbl)	NGL (per Bbl)	Natural gas (per Mcf)	Oil (per Bbl)	Natural gas (per Mcf)
December 31, 2018	$ 59.12	$ 24.91	$ 1.89	$ 65.56	$ 3.10
December 31, 2017	$ 47.70	$ 20.07	$ 2.13	$ 51.34	$ 2.98
December 31, 2016	$ 39.70	$ 14.11	$ 1.83	$ 42.75	$ 2.48

(2) Barrel of oil equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, which approximates the relative energy content of oil as compared to natural gas.
(3) PV-10 is the present value of estimated future net revenue to be generated from the production of proved reserves, discounted at 10% per annum to reflect timing of future cash flows and calculated without deducting future income taxes. PV-10 is a non-GAAP financial measure and generally differs from standardized measure of discounted net cash flows, or Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. Neither PV-10 nor Standardized Measure are intended to represent an estimate of fair market value of the Royalty Interests. PV-10 is used by the industry as an arbitrary reserve asset value measure to compare the relative size and value of the proved reserves held by companies without regard to the specific tax characteristics of such entities. The following table provides a reconciliation of Standardized Measure to PV-10:

	December 31,		
	2018	2017	2016
	(in millions)		
Standardized Measure of Discounted Net Cash Flows (4)	$ 135.5	$ 123.0	$ 109.6
Present value of future income tax discounted at 10%	0.2	0.2	0.3
PV-10	$ 135.7	$ 123.2	$ 109.9

(4) Standardized Measure represents the present value of estimated future cash inflows from proved oil, natural gas and NGL reserves, less future development and production costs, and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows and using the same pricing assumptions as are used to calculate PV-10. Standardized Measure differs from PV-10 as Standardized Measure includes the effect of future income taxes.

Proved reserves are those quantities of oil, natural gas and NGL that, 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 estimation. To be classified as proved reserves, the project to extract the oil or natural gas must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable period of time.

The area of a reservoir considered proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with the identified area and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establish a lower contact with reasonable certainty.

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

Reserves that can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir, or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which hydrocarbons can be economically produced from a reservoir can be determined. In determining the amount of proved reserves, the price used must be the average price during the

12-month period prior to the ending date of the period covered by the reserve report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved Undeveloped Reserves.

Under the terms of the development agreement, SandRidge was obligated to drill, or cause to be drilled, the Trust Development Wells by March 31, 2016. SandRidge fulfilled its drilling obligation to the Trust in November 2014. Accordingly, the Trust did not have any proved undeveloped reserves at December 31, 2018, 2017 and 2016, as no Trust Development Wells were drilled during the years ended December 31, 2018, 2017 and 2016 and none will be drilled in the future.

Production and Price History

The following tables set forth information regarding the net oil, natural gas and NGL production attributable to the Royalty Interests and certain price and cost information for each of the periods indicated.

	Year Ended December 31,		
	2018 (1)	2017 (2)	2016 (3)
Production Data			
Oil (MBbls)	485	584	723
NGL (MBbls)	72	83	94
Natural gas (MMcf)	227	281	307
Combined equivalent volumes (MBoe)(4)	595	714	869
Average daily combined equivalent volumes (MBoe/d)	1.6	2.0	2.4
Average Prices			
Oil (per Bbl)	$ 56.96	$ 45.44	$ 38.71
NGL (per Bbl)	$ 24.16	$ 19.27	$ 14.14
Combined oil and NGL (per Bbl)	$ 52.70	$ 42.18	$ 35.87
Natural gas (per Mcf)	$ 1.91	$ 2.30	$ 1.73
Combined equivalent (per Boe)	$ 50.08	$ 40.33	$ 34.37

Average Prices - including impact of post-production expenses						
Natural gas (per Mcf)	$	1.71	$	2.10	$	1.52
Combined equivalent (per Boe)	$	50.00	$	40.24	$	34.30
Expenses (per Boe)						
Post-production	$	0.08	$	0.08	$	0.07
Production taxes	$	2.39	$	1.93	$	1.63
Total expenses	$	2.47	$	2.01	$	1.70

(1) Production volumes and related revenues and expenses for the year ended December 31, 2018 (included in SandRidge’s 2018 net revenue distributions to the Trust) represent production from September 1, 2017 to August 31, 2018.
(2) Production volumes and related revenues and expenses for the year ended December 31, 2017 (included in SandRidge’s 2017 net revenue distributions to the Trust) represent production from September 1, 2016 to August 31, 2017.
(3) Production volumes and related revenues and expenses for the year ended December 31, 2016 (included in SandRidge’s 2016 net revenue distributions to the Trust) represent production from September 1, 2015 to August 31, 2016.
(4) Barrel of oil equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, which approximates the relative energy content of oil as compared to natural gas.

Productive Wells

The following table sets forth as of December 31, 2018 the number of productive wells subject to the Royalty Interests. Productive wells consist of producing wells and wells capable of producing. Gross wells are the total number of producing wells subject to the Royalty Interests and net wells are the sum of the Trust’s fractional royalty interests owned in gross wells.

	Oil		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Productive Wells	1,042	546.0	—	—	1,042	546.0

Developed and Undeveloped Acreage

As of December 2014, SandRidge had drilled and perforated for completion 888 equivalent Trust Development Wells, thus fulfilling its drilling obligation. Accordingly, the AMI terminated effective December 2014, and no additional wells have been or will be drilled for the Trust.

Drilling Activity

There were no wells drilled or completed during 2018 or 2017, and there were no wells subject to the Royalty Interests drilling or awaiting completion at December 31, 2018 or 2017.

Marketing and Customers

Avalon has, and SandRidge had prior to the Sale Transaction the responsibility to market, or cause to be marketed, the oil, natural gas and NGL production attributable to the Underlying Properties and is not permitted to charge any marketing fees when determining the net proceeds upon which the royalty payments are calculated, except for marketing fees and costs of non-affiliates. SandRidge performs these services on behalf of, and in conjunction with, Avalon pursuant to the terms of the transition services agreement, which terminates on March 31, 2019 unless otherwise extended by the parties. As a result, the net proceeds to the Trust from the sales of oil, natural gas and NGL production from the Underlying Properties for the years ended December 31, 2017 and December 31, 2018 are determined based on the same price (net of post-production costs) that SandRidge received for oil, natural gas and NGL production attributable to its interest in the Underlying Properties.

SandRidge sells oil, natural gas and NGL from the Underlying Properties to a variety of customers, including oil and natural gas companies and trading and energy marketing companies. During each of 2018 and 2017, two customers individually accounted for more than 10% of total revenue attributable to the Royalty Interests. The number of readily available purchasers for the production from the Underlying Properties makes it unlikely that the loss of a single customer in the areas in which SandRidge sells oil, natural gas and NGL production from the Underlying Properties would materially affect the Trust's revenue. The Trust is not committed under any existing contracts or agreements to provide fixed and determinable quantities of oil, NGL or natural gas in the future. See the table below for additional information on SandRidge's major customers for the production from the Underlying Properties.

	Sales (in thousands)		% of Revenue	
2018				
Enterprise Crude Oil LLC	$	22,685	76.0	%
ConocoPhillips Company	$	4,917	16.5	%
2017				
Enterprise Crude Oil LLC	$	21,947	76.2	%
	$	4,550	15.8	%

ConocoPhillips
Company

Title to Properties

The Underlying Properties are subject to certain burdens that are described in more detail below. To the extent that these burdens and obligations affect the rights of Avalon and, prior to the Sale Transaction, affected the rights of SandRidge, in production and the value of production from the Underlying Properties, they have been taken into account in calculating the Trust's interest and in estimating the size and value of the reserves attributable to the Royalty Interests. The Underlying Properties are typically subject, in one degree or another, to one or more of the following:

•royalties and other burdens, express and implied, under oil and natural gas leases;

•production payments and similar interests and other burdens created by SandRidge or its predecessors in title;

•a variety of contractual obligations arising under operating agreements, farmout agreements, production sales contracts and other agreements that may affect the Underlying Properties or their titles;

11

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

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

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

•conventional rights of reassignment that obligate Avalon to reassign all or part of a property to a third party if Avalon intends to release or abandon such property; and

•rights reserved to or vested in the appropriate governmental agency or authority to control or regulate the Underlying Properties.

Avalon believes that its title to the Underlying Properties and the Trust's title to the Royalty Interest are good and defensible in accordance with standards generally accepted in the oil and natural gas industry, subject to such exceptions as are not so material as to detract substantially from the use or value of such properties or Royalty Interests.

Competition and Markets

The production and sale of oil, natural gas and NGL is highly competitive. Competitors in the Permian Basin include major oil and gas companies, independent oil and gas companies, and individual producers and operators. There are numerous producers in the Permian Basin, and competitive position in this area is affected by price, contract terms and quality of service.

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

Future price fluctuations for oil, natural gas and NGL will directly impact Trust distributions, estimates of reserves attributable to the Royalty Interests and estimated and actual future net revenues to the Trust. Due to the many uncertainties that affect the supply and demand for oil, natural gas and NGL, reliable predictions of future oil, natural gas and NGL supply and demand, future product prices or the effect of future product prices on Trust distributions cannot be made. However, lower product prices will adversely affect Trust distributions.

Seasonal Nature of Business

Generally, demand for oil, natural gas and NGL decreases during the summer months and increases during the winter months. Certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can lessen seasonal demand fluctuations. Seasonal weather conditions and lease stipulations can limit producing activities and other oil and natural gas operations. These seasonal anomalies can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increased costs or delay operations.

Insurance

Insurance is maintained by the operators of the Underlying Properties, in accordance with industry practice, against some, but not all, of the operating risks to which the operators are exposed. Generally, insurance policies include coverage for general liability (including sudden and accidental pollution), physical damage to certain oil and natural gas properties, auto liability, worker's compensation and employer's liability, among other things.

Avalon maintains general liability insurance coverage up to $1 million per occurrence and $2 million aggregate policy limit, which includes (i) completed operations coverage and (ii) sudden and accidental environmental liability coverage for the effects of pollution on third parties, arising from operations. The general liability insurance policy contains limits subject to certain customary exclusions and limitations, as well as deductibles that must be met prior to recovery. In addition, Avalon maintains $25 million in excess liability coverage, which is in addition to and triggered if the general liability per occurrence limit is reached, and may be subject to a deductible that must be met prior to recovery. Avalon also maintains worker's compensation coverage in accordance with Texas statutory requirements and employee liability coverage of $1 million by accident or by disease.

All of Avalon's third-party contractors are required to sign master services agreements in which they agree to indemnify Avalon for injuries and deaths of the service provider's employees as well as contractors and subcontractors hired by the service provider. Similarly, Avalon generally agrees to indemnify each third-party contractor against claims made by employees of Avalon and Avalon's other contractors. Additionally, each party generally is responsible for damage to its own property.

The third-party contractors that perform hydraulic fracturing operations sign the master services agreements containing the indemnification provisions noted above. Currently there are no insurance policies in effect intended to provide coverage for losses solely related to hydraulic fracturing operations.

The purchase of insurance, coverage limits and deductibles is re-evaluated annually by Avalon. Future insurance coverage for the oil and natural gas industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that are economically acceptable. No assurance can be given that insurance may be maintained in the future at rates considered reasonable. Self-insurance or only catastrophic coverage may be elected for certain risks in the future.

The Trust does not maintain any insurance policies or coverage against any of the risks of conducting oil and gas exploration and production or related activities.

Regulation

Oil and Natural Gas Regulations. The oil and natural gas industry is extensively regulated by numerous federal, state, local and regional authorities, as well as Native American tribes. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, and Native American tribes are authorized by statute to issue rules and regulations affecting the oil and natural gas industry and its individual members, some of which carry substantial penalties for noncompliance. Although the regulatory burden on the oil and natural gas industry increases the cost of doing business and, consequently, affects its profitability, these burdens generally do not affect SandRidge or Avalon any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

The availability, terms and cost of transportation significantly affect sales of oil, natural gas and NGL. The interstate transportation and sale for resale of oil, natural gas and NGL is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission ("FERC"). Federal and state regulations govern the price and terms for access to oil and natural gas pipeline transportation. FERC's regulations for interstate oil and natural gas transmission in some circumstances may also affect the intrastate transportation of oil and natural gas.

However, sales of oil, natural gas and NGL produced from the Underlying Properties are not currently regulated and are transacted at market prices. Although oil, natural gas and NGL prices are currently unregulated, Congress historically has been active in the area of oil and natural gas regulation. Whether new legislation to regulate oil, natural gas and NGL prices might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on the operations of the Underlying Properties cannot be predicted.

Production. Operations are subject to various types of regulation at federal, state and local levels. These types of regulation include reports concerning operations. Most states, and some counties, municipalities and Native American tribal areas also regulate one or more of the following activities: the rates of production, or "allowables", the use of surface or subsurface waters, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells, and the notice to surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce Avalon's interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil, natural gas and NGL production from its wells or limit the number of wells or the locations which can be drilled. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGL within its jurisdiction.

Federal, state and local regulations provide detailed requirements for the abandonment of wells, closure or decommissioning of production facilities and pipelines, and for site restorations, in areas where the Underlying Properties are located. For example, the Railroad Commission of Texas imposes financial assurance requirements on operators, and the United States Army Corps of Engineers (“Corps”) and many other state and local authorities also have regulations for plugging and abandonment, decommissioning and site restoration.

Natural Gas Sales and Transportation.

The availability, terms and cost of transportation significantly affect sales of oil and natural gas. The interstate transportation and sale for resale of oil and natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by FERC. Federal and state regulations govern the price and terms for access to oil and natural gas pipeline transportation. FERC’s regulations for interstate oil and natural gas transmission in some circumstances may also affect the intrastate transportation of oil and natural gas.

Historically, federal legislation and regulatory controls have affected the price of the natural gas Avalon produces and the manner in which Avalon markets its production. FERC has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Various federal laws enacted since 1978 have resulted in the removal of all price and non-price controls for sale of domestic natural gas sold in first sales, which include all of Avalon’s sales of its own production. Under the Energy Policy Act of 2005, FERC has substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including the ability to assess substantial civil penalties.

FERC also regulates interstate natural gas transportation rates and service conditions and establishes the terms under which Avalon may use interstate natural gas pipeline capacity, which affects the marketing of natural gas produced from the Underlying Properties, as well as the revenues it receives for sales of its natural gas and release of its natural gas pipeline capacity. Commencing in 1985, FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Currently, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC’s initiatives have led to the development of a competitive, open access market for natural gas purchases and sales that permits all purchasers of natural gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, the less stringent regulatory approach currently pursued by FERC and Congress might not continue indefinitely into the future. Avalon is not able to determine what effect, if any, future regulatory changes might have on future natural gas related activities with respect to the Underlying Properties.

Under FERC’s current regulatory regime, transmission services must be provided on an open-access, nondiscriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states. Although its policy is still in flux, in the past FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase the cost of transporting gas to point-of-sale locations.

Oil Price Controls and Transportation Rates.

Sales prices of oil and NGL produced from the Underlying Properties are not currently regulated and are made at market prices. Sales of these commodities are, however, subject to laws and to regulations issued by the Federal Trade Commission (the “FTC”) prohibiting manipulative or fraudulent conduct in the wholesale petroleum market. The FTC holds substantial enforcement authority under these regulations, including the ability to assess substantial civil penalties.

The price received from the sale of these products may be affected by the cost of transporting the products to market. Some transportation of oil, natural gas and NGL is through interstate common carrier pipelines. Effective as of January 1, 1995, FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. FERC's regulation of crude oil and natural gas liquids transportation rates may tend to increase the cost of transporting crude oil and natural gas liquids by interstate pipelines, although the annual adjustments may result in decreased rates in a given year. Every five years, FERC must examine the relationship between the annual change in the applicable index and the actual cost changes experienced in the oil pipeline industry. Avalon is not able at this time to predict the effects of these regulations or FERC proceedings, if any, on the transportation costs associated with crude oil production from crude oil producing operations.

Environmental and Occupational Safety and Health Regulation. Oil, natural gas and NGL exploration, development and production operations are subject to stringent and complex federal, state, tribal, regional and local laws and regulations governing worker safety and health, the discharge and disposal of substances into the environment, and the protection of the environment and natural resources. Numerous governmental entities, including the U.S. Environmental Protection Agency ("EPA") and analogous state and local agencies, (and, under certain laws, private individuals) have the power to enforce compliance with these laws and regulations and any permits issued under them. These laws and regulations may, among other things; (i) require permits to conduct exploration, drilling, water withdrawal, wastewater disposal and other production related activities; (ii) govern the types, quantities and concentrations of substances that may be disposed or released into the environment or injected into formations in connection with drilling or production activities, and the manner of any such disposal, release or injection; (iii) limit or prohibit construction or require formal mitigation measures in sensitive areas such as wetlands, wilderness areas or areas inhabited by endangered or threatened species; (iv) require investigatory and remedial actions to mitigate pollution conditions arising from or attributable to former operations of the Underlying Properties; (v) impose safety and health restrictions designed to protect employees from exposure to hazardous or dangerous substances; and (vi) impose obligations to reclaim and abandon well sites and pits. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil and criminal penalties, the imposition of investigatory, remedial or corrective action obligations, the occurrence of delays or restrictions in permitting or performance of projects and the issuance of orders enjoining operations in affected areas.

Since taking office, the Trump Administration has taken steps aimed at reducing federal regulatory burdens and costs for the oil and gas industry. Nevertheless, changes in environmental regulation may place more restrictions and limitations on activities that may affect the environment. Any changes in or more stringent enforcement of these laws and regulations that result in delays or restrictions in permitting or development of projects, or more stringent or costly construction, drilling, water management or completion activities or waste handling, storage, transport, remediation, or disposal, emission or discharge requirements could have a material adverse effect on the Trust's revenues. Moreover, accidental releases, including spills, may occur in the course of operations on the Underlying Properties, and significant costs could be incurred as a result of such releases or spills, including third-party claims for damage to property and natural resources or personal injury. While Avalon believes that compliance with existing environmental laws and regulations and that continued compliance with existing requirements will not materially affect operation of the Underlying Properties, it is possible that Avalon may incur substantial costs in the future related to revised or additional environmental regulations that could have a material adverse effect on its business, financial condition, and results of operations and its operation of the Underlying Properties.

The following is a summary of the more significant existing and proposed environmental and occupational safety and health laws and regulations, as amended from time to time, to which the Underlying Properties and Avalon's business operations are subject and for which compliance may have a material adverse impact on the Trust or operation of the Underlying Properties.

Hazardous Substances and Wastes. The federal Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA") and comparable state laws may impose strict, joint and several liability, without regard to fault or legality of conduct on certain persons who are responsible for the release of a "hazardous substance" into the environment. These persons include current and prior owners or operators of the site where the release of a hazardous substance occurred as well as entities that disposed or arranged for the disposal of the hazardous substance released at the site. Under CERCLA, these "responsible parties" may be liable for the costs of cleaning up sites where hazardous substances have been released into the environment, for damages to natural resources resulting from the release and for the costs of certain environmental and health studies. Additionally, landowners and other third parties may file claims for personal injury and natural resource and property damage allegedly caused by the release of hazardous substances into the environment. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment from a hazardous substance release and to pursue steps to recover costs incurred for those actions from responsible parties. Despite the so-called "petroleum exclusion," certain products used by Avalon and used previously by SandRidge in the course of operations at the Underlying Properties may be regulated as CERCLA hazardous substances. To date, none of the Underlying Properties have been subject to

CERCLA response actions.

The federal Resource Conservation and Recovery Act (“RCRA”) and comparable state statutes and implementing regulations impose strict “cradle-to-grave” requirements on the generation, transportation, treatment, storage and disposal and cleanup of hazardous and non-hazardous wastes. SandRidge, Avalon and other operators of the Underlying Properties have and will generate wastes that are subject to the requirements of RCRA and comparable state statutes. Drilling fluids, produced waters and other wastes associated with the exploration, production and/or development of oil and natural gas, including naturally-occurring radioactive material, if properly handled, are currently excluded from regulation as hazardous wastes under RCRA and, instead, are regulated under RCRA’s less stringent non-hazardous waste requirements. However, it is possible that these wastes could be classified as hazardous wastes in the future. For example, in December 2016, the EPA and environmental groups entered into a consent decree to address the EPA’s alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production related oil and natural gas wastes from regulation as hazardous wastes under RCRA. The consent decree requires the EPA to propose a rulemaking no later than March 15, 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and natural gas wastes or to sign a determination that revision of the regulations is not necessary, and complete any revisions to the applicable RCRA regulations no later than July 15, 2021. Any change in the exclusion for such wastes could potentially result in an increase in the cost of managing and disposing of those wastes.

Air Emissions. The federal Clean Air Act ("CAA") and comparable state laws and regulations restrict the emission of air pollutants through emissions standards, construction and operating permitting programs, and the imposition of other compliance requirements. These laws and regulations may require pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, strict compliance with air permit requirements or the utilization of specific equipment or technologies to control emissions. The need to acquire such permits has the potential to delay or limit the development of oil and natural gas projects or require Avalon to incur certain capital expenditures for air pollution control equipment or other air emissions-related issues. For example, the EPA in 2012 adopted federal New Source Performance Standards ("NSPS") that require the reduction of volatile organic compound emissions from certain fractured and refractured natural gas wells for which well completion operations are conducted and further require that most wells use reduced emission completions, also known as "green completions." These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, and from pneumatic controllers and storage vessels. In June 2016, the EPA published a final rule adopting additional NSPS requirements for new, modified, or reconstructed oil and gas facilities that require control of the greenhouse gas methane from affected facilities, including requirements to find and repair fugitive leaks of methane emissions at well sites ("Methane Rule"). Following the 2016 presidential election and change in administrations, the EPA in 2017 proposed to delay implementation of the Methane Rule, and also convened a reconsideration proceeding that resulted in two 2018 rulemaking projects aimed at rolling back certain Methane Rule requirements. These actions, like the Methane Rule itself, have been (or are likely to be) challenged in courts. The ultimate fate of the Methane Rule requirements is unclear. Nevertheless, regulations promulgated under the CAA may require Avalon to incur development expenses to install and utilize specific equipment, technologies, or work practices to control emissions from its operations.

The EPA also is charged with establishing ambient air quality standards, the implementation of which can indirectly impact Avalon's operations. For example, in October 2015, the EPA lowered the National Ambient Air Quality Standard ("NAAQS"), for ozone from 75 to 70 parts per billion. A number of state and industry petitioners filed suit in the U.S. Court of Appeals for the District of Columbia Circuit, challenging the 2015 ozone NAAQS. The outcome of the litigation challenging the standard is unknown at this time. Although the EPA has designated all counties in which the Underlying Properties are located as attainment areas for the 2015 ozone standard, these determinations may be revised in the future. State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit Avalon's ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant.

Compliance with these and other air pollution control and permitting requirements has the potential to increase Avalon's production costs, which costs could be significant. Additionally, violations of lease conditions or regulations related to air emissions can result in civil and criminal penalties, as well as potential court injunctions curtailing operations and canceling leases. Such enforcement liabilities can result from either governmental or citizen enforcement.

Water Discharges. The federal Clean Water Act ("CWA") and analogous state laws and implementing regulations impose restrictions and strict controls regarding the discharge of pollutants into waters of the United States and waters of the states, respectively. Pursuant to these laws and regulations, the discharge of pollutants to regulated waters is prohibited unless it is permitted by the EPA, the U.S. Army Corps of Engineers ("ACE") or an analogous state agency. The discharge of wastewater from most onshore oil and gas exploration and production activities is currently prohibited east of the 98^{th} meridian. Additionally, in June 2016, the EPA issued a final rule implementing wastewater pre-treatment standards that prohibit onshore unconventional oil and natural gas extraction facilities from sending wastewater directly to publicly owned treatment works ("POTW"). Unconventional extraction facilities can send wastewater to a private centralized wastewater treatment facility that can either discharge treated water or send it to a POTW. The EPA is conducting a study of the treatment and discharge of oil and gas wastewater. Any restriction of disposal options for hydraulic fracturing waste and other changes to CWA discharge requirements may result in increased costs. SandRidge has not and Avalon does not presently discharge pollutants associated with the exploration, development and production of oil, natural gas and NGL on the Underlying Properties into federal or state waters.

In September 2015, new EPA and ACE rules defining the scope of the "waters of the United States," and EPA's and the ACE's jurisdiction, became effective ("2015 Rule"). The 2015 Rule has been challenged in multiple courts on the grounds that it unlawfully expands the reach of CWA programs. Due to the status of pending litigation, the 2015 Rule is currently in effect in 22 states. In the remaining states, regulations in effect before promulgation of the 2015 Rule and guidance interpreting relevant United States Supreme Court rulings are in effect. On December 11, 2018, the heads of the EPA and ACE signed a proposed regulation that would revise the definition of waters of the United States to reduce its reach from the 2015 Rule ("2018 Pre-Proposal Rule"). The fates of the 2015 Rule and the 2018 Pre-Proposal Rule and applicability of the rules during current and future litigation are uncertain; however, to the extent the 2015 Rule is in effect, it expands the scope of CWA

16

jurisdiction, and Avalon could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas or other waters of the United States.

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

Subsurface Injections. Any underground injection operations that may be performed by Avalon in the future are subject to the Safe Drinking Water Act ("SDWA"), as well as analogous state laws and regulations. Under the SDWA, the EPA established the Underground Injection Control ("UIC") program, which established the minimum program requirements for state and local programs regulating underground injection activities. The UIC program includes requirements for permitting, testing, monitoring, record keeping and reporting of injection well activities, as well as a prohibition against the migration of fluid containing any contaminant into underground sources of drinking water. State regulations require a permit from the applicable regulatory agencies to operate underground injection wells. SandRidge had such UIC permits and Avalon [has obtained/is obtaining] such UIC permits. Although Avalon monitors the injection process of its wells, any leakage from the subsurface portions of the injection wells could cause degradation of fresh groundwater resources, potentially resulting in suspension of Avalon's UIC permit, issuance of fines and penalties from governmental agencies, incurrence of expenditures for remediation of the affected resource and imposition of liability by third-parties claiming damages for alternative water supplies, property damages and personal injuries. Some states have considered laws mandating flowback and produced water recycling. Other states have undertaken studies to assess the feasibility of recycling produced water on a large scale. For example, in July 2018, the EPA partnered with New Mexico to evaluate alternatives to injection of wastewater from exploration and production activities by reusing it or treating it for reintroduction into the hydrologic cycle or both, and to propose potential regulations related thereto. If laws mandating reuse and/or treatment in lieu of injection are adopted for the counties in which the Underlying Properties are located, Avalon's operating costs may increase significantly.

Climate Change. In 2009, the EPA published its findings that emissions of carbon dioxide, methane and certain other "greenhouse gases" (collectively, "GHGs") present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. The EPA has taken a number of steps aimed at gathering information about, and reducing the emissions of, GHGs from industrial sources, including oil and natural gas sources. The EPA has adopted rules requiring the reporting of GHG emissions from oil, natural gas and NGL production and processing facilities on an annual basis, as well as reporting GHG emissions from gathering and boosting systems, oil well completions and workovers using hydraulic fracturing. The EPA also has adopted and implemented regulations under existing provisions of the CAA that, among other things, establish Prevention of Significant Deterioration ("PSD") construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that typically are established by the states. This rule could adversely affect Avalon's operations upon the Underlying Properties and restrict or delay its ability to obtain air permits for new or modified facilities that exceed GHG emission thresholds. In June 2016, the EPA published a final rule adopting New Source Performance Standards ("NSPS") for new, modified, or reconstructed oil and gas facilities that require control of the GHG methane from affected facilities, including requirements to find and repair fugitive leaks of methane emissions at well sites (“Methane Rule”). Following the 2016 presidential election and change in administrations, the EPA in 2017 proposed to delay implementation of the Methane Rule, and also convened a reconsideration proceeding that resulted in two 2018 rulemaking projects aimed at rolling back certain Methane Rule requirements. These actions, like the Methane Rule itself, have been (or are likely to be) challenged in courts. The ultimate fate of the Methane Rule requirements is unclear. Nevertheless, regulations promulgated under the CAA may require Avalon to incur development expenses to install and utilize specific equipment, technologies, or work practices to control emissions from its operations. In addition, in November 2016, the U.S. Department of the Interior Bureau of Land Management (“BLM”) issued final rules to reduce methane emissions from venting, flaring, and leaks during oil and gas operations on federal and tribal lands that are substantially similar to the EPA’s Methane Rule. However, in December 2017, the BLM published a final rule to temporarily suspend or delay certain requirements contained in the November 2016 final rule until January 17, 2019, including those requirements relating to venting, flaring and leakage from oil and gas production activities. Further, in September 2018, the BLM published a final rule revising or rescinding certain provisions of the 2016 rule. Although the future implementation of the EPA and BLM rules remains uncertain, future federal GHG regulations for the oil and gas industry remain a possibility given the long-term trend towards increasing regulation. Moreover, several states have already adopted rules requiring operators of both new and existing sources to develop and implement an LDAR program and to install devices on certain equipment to capture 95 percent of methane emissions. Compliance with these rules could require Avalon to purchase pollution control equipment and optical gas imaging equipment for LDAR inspections, and to hire additional personnel to assist with inspection and reporting requirements.

In addition, a number of state and regional efforts are aimed at tracking and/or reducing GHG emissions by means of cap-and-trade programs that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. On an international level, the United States is one of almost 200 nations that agreed in December 2015 to an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will use to achieve its GHG emissions targets, (the "Paris Agreement"). However, the Paris Agreement does not impose any binding obligations on the United States. Moreover, in June 2017, President Trump announced that the United States would withdraw from the Paris Agreement, but may enter into a future international agreement related to GHGs. In August 2017, the U.S. State Department officially informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. Such withdrawal has not yet been finalized, and whether the United States may reenter the Paris Agreement or a separately negotiated agreement is unclear at this time. Further, several states and local governments remain committed to the principles of the Paris Agreement in their effectuation of policy and regulations. It is not possible at this time to predict how or when the United States might impose restrictions on GHGs as a result of the Paris Agreement. The adoption and implementation of any laws or regulations imposing reporting obligations on, or limiting emissions of GHGs from operations could require additional expenditures to reduce emissions of GHGs associated with operations or could adversely affect demand for the oil, natural gas and NGL production attributable to the Royalty Interests, and thus possibly have a material adverse effect on the Trust's revenues. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and gas will continue to represent a substantial percentage of global energy use over that time. Finally, to the extent increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events, such events could have an adverse effect on assets and operations related to the Underlying Properties.

Endangered Species. The federal Endangered Species Act ("ESA") restricts activities that may affect endangered or threatened species or their habitats without first obtaining an incidental take permit and implementing mitigation measures. Similar protections are offered to migratory birds under the federal Migratory Bird Treaty Act. If endangered species are located in areas of the Underlying Properties where seismic surveys, development activities or abandonment operations may be conducted, the work could be prohibited or delayed or expensive mitigation may be required. In February 2016, the U.S. Fish and Wildlife Service ("USFWS") published a final policy which alters how it identifies critical habitat for endangered and threatened species. In July 2018, the USFWS proposed several changes to ESA regulations, including changes to the procedures and criteria for listing or removing species from the Lists of Endangered and Threatened Wildlife and Plants and for designating critical habitat. A critical habitat designation could result in further material restrictions to federal and private land use and could delay or prohibit land access or development. The designation of previously unprotected species as threatened or endangered in areas where operations on the Underlying Properties are located could cause Avalon to incur increased costs arising from species protection measures or could result in limitations on exploration and production activities that could have an adverse impact on the ability to develop and produce reserves from the Underlying Properties.

Employee Health and Safety. The operations of Avalon are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSHA Hazard Communication Standard requires Avalon to maintain information concerning hazardous materials used or produced in its operations and to provide this information to employees. Pursuant to the Federal Emergency Planning and Community Right-to-Know Act, facilities that store hazardous chemicals that are subject to OSHA's Hazard Communication Standard above certain threshold quantities must submit information regarding those chemicals by March 1 of each year to state and local authorities in order to facilitate emergency planning and response. That information is generally available to employees, state and local governmental authorities, and the public. SandRidge had been submitting, and Avalon will continue to submit, this information to these authorities for the Underlying Properties each year.

State and Local Regulation. The Underlying Properties are subject to state and other local regulations applicable to the drilling for, and the production and gathering of, oil, natural gas and NGL, including requirements relating to drilling permits, the location, spacing and density of wells, unitization and pooling of interests, the method of drilling, casing and equipping of wells, the protection of fresh water sources, the orderly development of common sources of supply of oil, natural gas and NGL, the operation of wells, allowable rates of production, the use of fresh water in oil and natural gas operations, saltwater injection

18

and disposal operations, the plugging and abandonment of wells and the restoration of surface properties, the prevention of waste of oil and natural gas resources, the protection of the correlative rights of oil and natural gas owners and, where necessary to avoid unfair, unjust or discriminatory service, the fees, terms and conditions for the gathering of natural gas. These regulations may affect the amounts of oil, natural gas and NGL that may be produced from the Underlying Properties. Realized prices for the first sale of oil, natural gas and NGL are not subject to state regulation in Texas.

Glossary of Oil and Natural Gas Terms

The following is a description of the meanings of some of the oil and natural gas industry terms used in this report.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to oil or other liquid hydrocarbons.

Boe. Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil. Although an equivalent barrel of condensate or natural gas may be equivalent to a barrel of oil on an energy basis, it is not equivalent on a value basis as there may be a large difference in value between an equivalent barrel and a barrel of oil. For example, based on the commodity prices used to prepare the estimate of the Trust's reserves at year-end 2018 of $65.56/ Bbl for oil and $3.10/ Mcf for natural gas, the ratio of economic value of oil to natural gas was approximately 21 to 1, even though the ratio for determining energy equivalency is 6 to 1.

Boe/d. Barrels of oil equivalent per day.

Btu or British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas, or in the case of a dry well, the reporting to the appropriate authority that the well has been abandoned.

Developed acreage. The number of acres that are assignable to productive wells.

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.

Development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Gross wells. The total wells in which a working interest is owned.

MBbls. Thousand barrels of oil or other liquid hydrocarbons.

MBoe. Thousand barrels of oil equivalent.

MBoe/d. Thousand barrels of oil equivalent per day.

Mcf. Thousand cubic feet of natural gas.

MMBoe. Million barrels of oil equivalent.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

Net wells. The sum of the fractional working interest owned in gross wells, as the case may be.

Net revenue interests. A share of production after all burdens, such as royalty and overriding royalty interest, have been deducted from the working interest.

NGL. Natural gas liquids, such as ethane, propane, butanes and natural gasolines that are extracted from natural gas production streams.

Plugging and abandonment. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Texas regulations require plugging of abandoned wells.

Present value of future net revenues (“PV-10”). The present value of estimated future revenues to be generated from the production of proved reserves, before income taxes, calculated in accordance with SEC guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation and without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization. PV-10 is calculated using an annual discount rate of 10%.

Production costs. Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities that become part of the cost of oil, natural gas and NGL produced.

Productive well. A well that is found to be capable of producing oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

Proved developed reserves. Reserves that are both proved and developed.

Proved oil, natural gas and NGL reserves. Those quantities of oil, natural gas and NGL that, 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 estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

The area of a reservoir considered proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establish a lower contact with reasonable certainty.

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

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

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

Proved undeveloped reserves. Reserves that are both proved and undeveloped.

PV-10. See “Present value of future net revenues” above.

Reserves. Estimated remaining quantities of oil, natural gas and NGL and related substances anticipated to be economically producible 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, natural gas and NGL or related substances to market, and all permits and financing required to implement the project.

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

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

Standardized measure or standardized measure of discounted future net cash flows. The present value of estimated future cash inflows from proved oil, natural gas and NGL reserves, less future development and production costs and future income tax expenses, discounted at 10% per annum to reflect timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized Measure differs from PV-10 because Standardized Measure includes the effect of future income taxes on future net revenues.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or natural gas regardless of whether such acreage contains proved reserves.

Undeveloped oil, natural gas and NGL 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.

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

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

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

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.

Item 1A. Risk Factors

Risks Related to the Units

Producing oil, natural gas and NGL from the Underlying Properties is a high risk activity with many uncertainties that could adversely affect future production from the Underlying Properties. Any such reductions in production could decrease cash that is available for distribution to unitholders.

Production operations on the Underlying Properties may be curtailed, delayed or canceled as a result of various factors, including the following:

•reductions in oil, natural gas and NGL prices;

•unusual or unexpected geological formations and miscalculations;

•equipment malfunctions, failures or accidents;

21

•lack of available gathering facilities or delays in construction of gathering facilities;

•lack of available capacity on interconnecting transmission pipelines;

•lack of adequate electrical infrastructure and water disposal capacity;

•unexpected operational events;

•pipe or cement failures and casing collapses;

•pressures, fires, blowouts and explosions;

•uncontrollable flows of oil, NGL, natural gas, brine, water or drilling fluids;

•natural disasters;

•environmental hazards, such as oil spills, natural gas and NGL leaks, pipeline or tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;

•high costs, shortages or delivery delays of equipment, labor or other services, or water used in hydraulic fracturing;

•compliance with environmental and other governmental requirements;

•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, natural gas and NGL.

If production from the Trust Development Wells is lower than anticipated due to one or more of the foregoing factors or for any other reason, cash distributions to unitholders may be reduced.

Oil, natural gas and NGL prices can fluctuate widely due to a number of factors that are beyond the control of the Trust and Avalon. Continued volatility in oil, natural gas or NGL prices could reduce proceeds to the Trust and cash distributions to unitholders.

The value of the Trust’s reserves and amount available for quarterly cash distributions to Trust unitholders are highly dependent upon the prices realized from the sale of oil, natural gas and NGL produced from the Underlying Properties. Historically, the markets for these hydrocarbons have been very volatile. Prices for oil, natural gas and NGL can move quickly and fluctuate widely in response to a variety of factors that are beyond the control of the Trust, SandRidge or Avalon. These factors include, among others:

•changes in regional, domestic and foreign supply of, and demand for, oil, natural gas and NGL, as well as perceptions of supply of, and demand for, oil, natural gas and NGL generally;

•the price and quantity of foreign imports;

•the ability of other companies to complete and commission liquefied natural gas export facilities in the U.S.;

•U.S. and worldwide political and economic conditions;

•weather conditions and seasonal trends;

•anticipated future prices of oil, natural gas and NGL, alternative fuels and other commodities;

•technological advances affecting energy consumption and energy supply;

•the proximity, capacity, cost and availability of pipeline infrastructure, treating, transportation and refining capacity;

•natural disasters and other extraordinary events;

•domestic and foreign governmental regulations and taxation;

•energy conservation and environmental measures; and

•the price and availability of alternative fuels.

These factors and the volatility of the energy markets, which is expected to continue, make it extremely difficult to predict future oil, natural gas and NGL price movements with any certainty. For oil, from January 2017 through December 2018, the highest month-end settled price on the New York Mercantile Exchange (“NYMEX”) was $74.15 per Bbl and the lowest was $45.41 per Bbl. For natural gas, from January 2017 through December 2018, the highest month-end NYMEX settled price was $4.61 per MMBtu and the lowest was $2.66 per MMBtu. In addition, the market price of oil and natural gas is generally lower in the summer months than during the winter months of the year due to decreased demand for oil and natural gas for heating purposes during the summer season.

Oil, natural gas and NGL prices experienced substantial fluctuations during 2018 and declined significantly in the fourth quarter. A buildup in inventories, lower global demand, or other factors could cause prices for U.S. oil, natural gas and NGL to weaken further. Continued low oil, natural gas and NGL prices will reduce proceeds to which the Trust is entitled and may ultimately reduce the amount of oil, natural gas and NGL that is economic to produce from the Underlying Properties causing the Trust to make substantial downward adjustments to its estimated proved reserves. As a result, Avalon or any third-party operator of any of the Underlying Properties could determine during periods of low oil, natural gas or NGL 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, natural gas or NGL 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, Avalon or any third-party operator may abandon, at its cost, any well or property if it reasonably believes that the well or property can no longer produce oil, natural gas and NGL in commercially economic quantities. This could result in termination of the portion of the Royalty Interest relating to the abandoned well or property, and Avalon has no obligation to drill a replacement well.

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

The value of the Trust units and the amount of future cash distributions to the Trust unitholders will depend upon, among other things, the accuracy of the reserves estimated to be attributable to the Royalty Interests. It is not possible to accurately measure underground accumulations of oil, natural gas and NGL in an exact way and estimating reserves is inherently uncertain. As discussed below, the process of estimating oil, natural gas and NGL reserves requires interpretations of available technical data and many assumptions. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of the Trust’s reserves. This could result in actual production and revenues for the Underlying Properties being materially less than estimated amounts.

In order to prepare the estimates of reserves attributable to the Underlying Properties and the Royalty Interests, production rates must be projected. In so doing, available geological, geophysical, production and engineering data must be analyzed. The extent, quality and reliability of this data can vary.

In addition, petroleum engineers are required to make subjective estimates of underground accumulations of oil, natural gas and NGL based on factors and assumptions that include:

•historical production from the area compared with production rates from other producing areas;

•oil, natural gas and NGL prices, production levels, Btu content, production expenses, transportation costs, severance and excise taxes and capital expenditures; and

•the assumed effect of governmental regulation.

Changes in these assumptions or actual production costs incurred could materially decrease reserve estimates. Estimates of reserves are also continually subject to revisions based on production history, price changes and other factors.

A material and adverse variance of actual production, revenues and expenditures from those underlying reserve estimates would have a material adverse effect on the financial condition, results of operations and cash flows of the Trust and would reduce cash distributions to Trust unitholders. As a result, the Trust may not receive the benefit of the total amount of reserves reflected in the reserve report, notwithstanding the fact that SandRidge satisfied its drilling obligation.

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

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

- evacuation of personnel and curtailment of operations;
- weather-related damage to 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 unitholders.

The Underlying Properties are being and will be operated for oil, natural gas and NGL production only and are focused exclusively in the Permian Basin in Andrews County, Texas. 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 market 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 Interests were more diversified.

The generation of proceeds for distribution by the Trust depends in part on access to and the operation of gathering, transportation and processing facilities. Limitations in the availability of those facilities could interfere with sales of oil, natural gas and NGL production from the Underlying Properties.

The amount of oil, natural gas and NGL that may be produced and sold from any well to which the Underlying Properties relate is subject to (a) curtailment of production in certain circumstances, such as by reason of weather, pump failure, down-hole issues or other operating risks common to the production of hydrocarbons, and (b) the availability of adequate transportation services, which has been an issue in the Permian Basin during 2018, or the curtailment of transportation services, including pipeline interruptions due to scheduled and unscheduled maintenance, failure of tendered oil, natural gas and NGL to meet quality specifications of gathering lines or downstream transporters, excessive line pressure which prevents delivery, physical damage to the gathering system or transportation system or lack of contracted capacity on such systems. The curtailments may vary from a few days to several months. In many cases, Avalon is provided limited notice, if any, as to when production will be curtailed and the duration of such curtailments. If Avalon is forced to reduce production due to such a curtailment or other interruption of transportation services, the revenues of the Trust and the amount of cash distributions to the Trust unitholders would similarly be reduced due to the reduction of proceeds from the sale of production.

The Trust is passive in nature and has no voting rights in Avalon, managerial, contractual or other ability to influence Avalon, or exercise control over the field operations of, or sale of oil, natural gas and NGL from the Underlying Properties.

Trust unitholders have no voting rights with respect to Avalon and, therefore, have no managerial, contractual or other ability to influence Avalon’s activities or operations of the Underlying Properties. In addition, some of the Underlying Properties may, in the future, be operated by third parties unrelated to Avalon. Such third-party operators may not have the operational expertise of Avalon. Oil and natural gas properties are typically managed pursuant to an operating agreement among the working interest owners in the properties. The typical operating agreement contains procedures whereby the owners of the aggregate working interest in the property designate one of the interest owners to be the operator of the property. Under these arrangements, the operator is typically responsible for making all decisions relating to sale of production, compliance with regulatory requirements and other matters that affect the property. The failure of an operator to adequately perform operations could reduce production from the Underlying Properties and cash available for distribution to unitholders. Neither the Trustee nor the Trust unitholders has any contractual or other ability to influence or control the field operations of, sale of oil, natural gas and NGL from, or future development of, the Underlying Properties.

The oil, natural gas and NGL reserves estimated to be attributable to the Royalty Interests are depleting assets and production from those reserves will diminish over time. Furthermore, the Trust is precluded from acquiring other oil and natural gas properties or royalty interests to replace the depleting assets and production.

The proceeds payable to the Trust from the Royalty Interests are derived from the sale of the production of oil, natural gas and NGL from the Underlying Properties. The oil, natural gas and NGL reserves attributable to the Royalty Interests are depleting assets, which means that the reserves of oil, natural gas and NGL attributable to the Royalty Interests will decline over time as will the quantity of oil, natural gas and NGL produced from the Underlying Properties.

Future maintenance may affect the quantity of proved reserves that can be economically produced from the Underlying Properties to which the wells relate. The timing and size of these projects will depend on, among other factors, the market prices of oil, natural gas and NGL. Avalon has no contractual obligation to make capital expenditures on the Underlying Properties in the future. Furthermore, for properties on which Avalon is not designated as the operator, Avalon has no control over the timing or amount of those capital expenditures. Avalon also has the right to non-consent and not participate in the capital expenditures on properties for which it is not the operator, in which case Avalon and the Trust will not receive the production resulting from such capital expenditures. If Avalon or other operators of the wells to which the Underlying Properties relate do not implement maintenance projects when warranted, the future rate of production decline of proved reserves may be higher than the rate currently expected by Avalon or estimated in the Trust's reserve report.

The trust agreement generally limits the Trust's business activities to owning the Royalty Interests and entering into the hedging arrangements and activities reasonably related thereto, including activities required or permitted by the terms of the conveyances related to the Royalty Interests. As a result, 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.

An increase in the differential between the price realized by Avalon for oil and natural gas produced from the Underlying Properties and the NYMEX or other benchmark price of oil or natural gas could reduce the proceeds to the Trust and therefore the cash distributions by the Trust and the value of Trust units.

The prices received for oil and natural gas production usually fall below benchmark prices such as NYMEX. The difference between the price received and the benchmark price is called a differential. The amount of the differential depends on a variety of factors, including discounts based on the quality and location of hydrocarbons produced, Btu content and post-production costs, including transportation. These factors can cause differentials to be volatile from period to period. Sellers of production have little or no control over the factors that determine the amount of the differential, and cannot accurately predict differentials for natural gas or crude oil. Increases in the differential between the realized price of oil or natural gas and the benchmark price for oil or natural gas could reduce the proceeds to the Trust and therefore the cash distributions made by the Trust and the value of the Trust units. Due to the cost of transportation in the Permian Basin (in part caused by a lack of pipeline capacity in certain fields), the differential has fluctuated significantly during 2018 and adversely impacted the net prices for oil and natural gas produced from the Underlying Properties. This trend is expected to continue in the first half of 2019 with improving conditions during the latter half of 2019 as new pipelines are available for transportation of oil and natural gas.

The amount of cash available for distribution by the Trust is reduced by Trust expenses, post-production costs and applicable taxes associated with the Royalty Interests.

The Royalty Interests and the Trust bear certain costs and expenses that reduce the amount of cash received by or available for distribution by the Trust to the holders of the Trust units. These costs and expenses include the following:

•the Trust's share of the costs incurred by Avalon to gather, store, compress, transport, process, treat, dehydrate and market the oil, natural gas and NGL (excluding costs of marketing services provided by Avalon);

•the Trust's share of applicable taxes, including property taxes and taxes on the production of oil, natural gas and NGL;

•the Trust's liability for Texas franchise tax; and

•Trust administrative expenses, including fees paid to the Trustee and the Delaware Trustee, the annual administrative services fee payable to Avalon, tax return and Schedule K-1 preparation and mailing costs, independent auditor fees and registrar and transfer agent fees, and costs associated with annual and quarterly reports to unitholders.

In addition, the amount of funds available for distribution to unitholders is reduced by the amount of any cash reserves maintained by the Trustee in respect of anticipated future Trust administrative expenses. As announced in December 2018, the Trustee intends to withhold the greater of $190,000 or 3.5% of the funds otherwise available for distribution each quarter to gradually increase cash reserves by a total of approximately $2,275,000, commencing with the distribution payable in the first quarter of 2019. In February 2019, the Trustee withheld $190,000 from the funds otherwise available for distribution.

The amount of post-production costs, taxes and expenses borne by the Trust may vary materially from quarter-to-quarter. The extent by which the costs and expenses of the Trust are higher or lower in any quarter will directly decrease or increase the amount received by the Trust and available for distribution to the unitholders. Historical post-production costs and taxes, however, may not be indicative of future post-production costs and taxes.

The Trust has no hedges in place to protect against the price risk inherent in holding interests in oil, a commodity that is frequently characterized by significant price volatility.

The Trust and SandRidge were parties to a derivatives agreement that provided the Trust with the economic effect of certain derivative contracts between SandRidge and a third party for production through March 31, 2015. From inception through the termination of the hedging arrangements, the Trust received approximately $47.5 million that it would not have received without the hedging arrangements. The last of the hedging arrangements expired on March 31, 2015. Consequently, Trust unitholders no longer have the benefit of any hedging arrangements, and all production after March 31, 2015 is subject to the price risks inherent in holding interests in oil, a commodity that is frequently characterized by significant price volatility.

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

The business and affairs of the Trust are administered by the Trustee. A Trust unitholder’s voting rights are more limited than those of stockholders of most public corporations. For example, there is no requirement for annual meetings of Trust unitholders or for an annual or other periodic re-election of the Trustee. The trust agreement provides that the Trustee may only be removed and replaced by the holders of a majority of the outstanding Trust units, excluding Trust units held by Avalon, voting in person or by proxy at a special meeting of Trust unitholders at which a quorum is present called by either the Trustee or the holders of not less than 10% of the outstanding Trust units. As a result, it may be difficult for Trust unitholders to remove or replace the Trustee without the cooperation of holders of a substantial percentage of the outstanding Trust units.

Trust unitholders have limited ability to enforce provisions of the Royalty Interests, and Avalon’s liability to the Trust is limited.

The trust agreement permits the Trustee and the Trust to sue Avalon or any other future owner of the Underlying Properties to enforce the terms of the conveyances creating the Royalty Interests. If the Trustee does not take appropriate action to enforce provisions of the conveyances, a Trust unitholder’s recourse would be limited to bringing a lawsuit against the Trustee to compel the Trustee to take specified actions. The trust agreement expressly limits a Trust unitholder’s ability to directly sue Avalon or any other party other than the Trustee. As a result, Trust unitholders will not be able to sue Avalon or any future owner of the Underlying Properties to enforce the Trust’s rights under the conveyances. Furthermore, the conveyances provide that, except as set forth in the conveyances, Avalon will not be liable to the Trust for the manner in which it performs its duties in operating the Underlying Properties as long as it acts in good faith and, to the fullest extent permitted by law, will owe no fiduciary duties to the Trust or the Trust unitholders.

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

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

26

The sale of Trust units by Avalon could have an adverse impact on the trading price of the Trust units.

As of March 7, 2019, Avalon owned 13,125,000 Trust units, all of which are pledged as collateral on the company's secured revolving line of credit. So long as the line of credit is outstanding, Avalon does not have the right to sell any or all of such Trust units without the prior consent of its lender. In the event Avalon could obtain the permission of its lender to sell Trust units, any such sale could have an adverse impact on the price of the Trust units depending on the number and manner in which the Trust units are sold.

Avalon could have interests that conflict with the interests of the Trust and Trust unitholders.

As a working interest owner in the Underlying Properties, Avalon could have interests that conflict with the interests of the Trust and the Trust unitholders. For example:

•Notwithstanding its fulfillment of its drilling obligation to the Trust, Avalon's interests may conflict with those of the Trust and the Trust unitholders in situations involving the maintenance, operation or abandonment of the Underlying Properties. Additionally, Avalon may, consistent with its obligation to act as a reasonably prudent operator, abandon a well that is uneconomic or not generating revenues from production in excess of its operating costs, even though such well is still generating revenue for the Trust unitholders. Avalon may make decisions with respect to expenditures and decisions to allocate resources on projects in other areas that adversely affect the Underlying Properties, including reducing expenditures on these properties, which could cause oil, natural gas and NGL production to decline at a faster rate and thereby result in lower cash distributions by the Trust in the future.

•Avalon may, without the consent or approval of the Trust unitholders, sell all or any part of its retained interest in the Underlying Properties, if the Underlying Properties are sold subject to and burdened by the Royalty Interests. Such sale may not be in the best interests of the Trust and Trust unitholders. For example, any purchaser may lack Avalon's experience in the Permian Basin or its creditworthiness.

•Avalon may, without the consent or approval of the Trust unitholders, require the Trust to release Royalty Interests with an aggregate value of up to $5.0 million during any 12-month period in connection with a sale by Avalon of a portion of its retained interest in the Underlying Properties. The fair value received by the Trust for such Royalty Interests may not fully compensate the Trust for the value of future production attributable to the Royalty Interests disposed of.

•Avalon is permitted under the conveyances creating the Royalty Interests to enter into new processing and transportation contracts without obtaining bids from or otherwise negotiating with any independent third parties, and Avalon will deduct from the Trust's proceeds any charges under such contracts attributable to production from the Trust properties.

•Avalon can sell its Trust units regardless of the effects such sale may have on common unit prices or on the Trust itself. Additionally, Avalon can vote its Trust units in its sole discretion.

In addition, Avalon has agreed that, if at any time the Trust's cash on hand (including available cash reserves) is not sufficient to pay the Trust's ordinary course administrative expenses as they become due, Avalon will, at the Trustee's request, loan funds to the Trust necessary to pay such expenses. Any such loan will be on an unsecured basis, and the terms of such loan will be substantially the same as those which would be obtained in an arms' length transaction between Avalon and an unaffiliated third party. If Avalon provides such funds to the Trust, it would become a creditor of the Trust and its interests as a creditor could conflict with the interests of unitholders.

Avalon may sell all or a portion of the Underlying Properties, subject to and burdened by the Royalty Interests; any such purchaser could have a weaker financial position and/or be less experienced in oil and natural gas development and production than Avalon.

Unitholders will not be entitled to vote on any sale of the Underlying Properties if the Underlying Properties are sold subject to and burdened by the Royalty Interests and the Trust will not receive any proceeds from any such sale. The purchaser would be responsible for all of Avalon’s obligations relating to the Royalty Interests on the portion of the Underlying Properties sold, and Avalon would have no continuing obligation to the Trust for those properties. Additionally, Avalon may enter into farmout or joint venture arrangements with respect to the wells burdened by the Trust’s Royalty Interest. Any purchaser, farmout counterparty or joint venture partner could have a weaker financial position and/or be less experienced in oil and natural gas development and production than Avalon.

The value of the Royalty Interests is highly dependent on the performance and financial condition of Avalon.

As of November 1, 2018, Avalon is the operator of all of the Initial Wells together with the wells drilled as Trust Development Wells through December 31, 2014. The conveyances provide that Avalon is obligated to market, or cause to be marketed, the oil, natural gas and NGL produced from the Underlying Properties. If Avalon were to default on its obligation, the cash distributions to the Trust unitholders may be materially reduced. The Trust is highly dependent on its Trustor, Avalon, for multiple services, including the operation of the Trust wells, remittance of net proceeds from the sale of associated production to the Trust, administrative services such as accounting, tax preparation, bookkeeping and informational services performed on behalf of the Trust. Due to the Trust's reliance on Avalon to fulfill these obligations, the value of the Royalty Interests and its ultimate cash available for distribution is highly dependent on Avalon's performance.

The bankruptcy of operators could impede the operation of wells.

The value of the Royalty Interests and the Trust's ultimate cash available for distribution is highly dependent on the financial condition of the operator of the wells. Avalon has not 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, natural gas and NGL, prevailing economic conditions and financial, business and other factors, many of which are beyond the control of such operators.

In the event of any future bankruptcy of Avalon or any other future operator of the Underlying Properties, the value of the Royalty Interests could be adversely affected by, among other things, delay or cessation of payments under the Royalty Interests, business disruptions or cessation of operations by the operator, replacements of operators, inability to find a replacement operator if necessary, reduced production of reserves, or decreased distributions to Trust unitholders.

Oil and natural gas wells are subject to operational hazards that can cause substantial losses. Avalon maintains insurance but may not be adequately insured for all such hazards.

There are a variety of operating risks inherent in oil, natural gas and NGL production and associated activities, such as fires, leaks, explosions, mechanical problems, major equipment failures, blowouts, uncontrollable flow of oil, natural gas, NGL, water or drilling fluids, casing collapses, abnormally pressurized formations and natural disasters. The occurrence of any of these or similar accidents that temporarily or permanently halt the production and sale of oil, natural gas and NGL at any of the Underlying Properties will reduce Trust distributions by reducing the amount of proceeds available for distribution.

Additionally, if any of such risks or similar accidents occur, Avalon could incur substantial losses as a result of injury or loss of life, severe damage or destruction of property, natural resources and equipment, regulatory investigation and penalties and environmental damage and clean-up responsibility. If Avalon experiences any of these problems, its ability to conduct operations and perform its obligations to the Trust could be adversely affected. While Avalon maintains insurance coverage it deems appropriate for these risks with respect to the Underlying Properties, Avalon's operations may result in liabilities exceeding such insurance coverage or liabilities not covered by insurance. If a well is damaged, Avalon would have no obligation to drill a replacement well or make the Trust whole for the loss. The Trust does not maintain any type of insurance against any of the risks of conducting oil and gas exploration and production and related activities.

The operation of the Underlying Properties is subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner and feasibility of conducting operations on the 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, natural gas and NGL production, transportation and treatment operations are subject to complex and stringent laws and regulations. In order to conduct operations in compliance with these laws and regulations, numerous permits, approvals and certificates are required from various federal, state and local governmental authorities. Compliance with these existing laws and regulations may require the incurrence of substantial costs by Avalon or other operators of the Underlying Properties. Additionally, there has been a variety of regulatory initiatives at the federal and state levels to further regulate oil and natural gas operations in certain locations. Any increased regulation or suspension of oil and natural gas operations, or revision or reinterpretation of existing laws and regulation, could result in delays and higher operating costs. Such costs or significant delays 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.

Laws and regulations governing oil and natural gas exploration and production may also affect production levels. Avalon is required to comply with federal and state laws and regulations governing conservation matters, including provisions related to the unitization or pooling of the oil and natural gas properties; the establishment of maximum rates of production from wells; the spacing of wells; and the plugging and abandonment of wells. These and other laws and regulations can limit the amount of oil, natural gas and NGL Avalon can produce from its wells, which in turn could negatively impact Trust distributions, estimated and actual future net revenues to the Trust and estimates of reserves attributable to the Trust's interests.

New laws or regulations, or changes to existing laws or regulations may unfavorably impact Avalon, could result in increased operating costs and could have a material adverse effect on Avalon's financial condition and results of operations.

Additionally, federal and state regulatory authorities may expand or alter applicable pipeline safety laws and regulations, compliance with which may require increased capital expenditures by Avalon and third-party downstream oil, natural gas and NGL transporters. These and other potential regulations could increase Avalon's operating costs, reduce Avalon's liquidity, delay Avalon's operations, increase direct and third-party post production costs associated with the Trust's interests or otherwise alter the way Avalon conducts its business, which could have a material adverse effect on Avalon's financial condition, results of operations and cash flows and which could reduce cash received by or available for distribution, including any amounts paid by Avalon for transportation on downstream interstate pipelines.

Should Avalon fail to comply with all applicable statutes, rules, regulations and orders of FERC or the FTC, Avalon could be subject to substantial penalties and fines.

Under the Energy Policy Act of 2005 and implementing regulations, FERC prohibits market manipulation in connection with the purchase or sale of natural gas. The FTC also prohibits manipulative or fraudulent conduct in the wholesale petroleum market with respect to sales of commodities, including crude oil, condensate and natural gas liquids. These agencies have substantial enforcement authority, including the ability to impose penalties for current violations in excess of $1 million per day for each violation. FERC has also imposed requirements related to reporting of natural gas sales volumes that may impact the formation of prices indices. Additional rules and legislation pertaining to these and other matters may be considered or adopted from time to time. Failure to comply with these or other laws and regulations administered by these agencies could subject Avalon to criminal and civil penalties, as described in Item 1 under "Regulation—Oil and Natural Gas Regulations."

The operation of the Underlying Properties is subject to environmental and occupational safety and health laws and regulations that could adversely affect the cost, manner or feasibility of conducting operations or result in significant costs and liabilities.

The oil, natural gas and NGL production operations on the Underlying Properties are subject to stringent and complex federal, state, regional and local laws and regulations governing worker safety and health, the discharge and disposal of materials into the environment or otherwise relating to environmental protection. Failure to comply with these laws and regulations may result in litigation; the assessment of sanctions, including administrative, civil and criminal penalties; the imposition of investigatory, remedial or corrective action obligations; the occurrence of delays or restrictions in permitting or performance of projects; and the issuance of orders and injunctions limiting or preventing some or all operations relating to the Underlying Properties in affected areas.

Under certain environmental laws and regulations, an owner or operator of the Underlying Properties could be subject to strict, joint and several strict liability for the investigation, removal or remediation of previously released materials or property contamination, regardless of whether the owner or operator was responsible for the release or contamination or whether the operations were in compliance with all applicable laws at the time the release or contamination occurred. Private parties, including the owners of properties upon which wells are drilled or facilities where petroleum hydrocarbons or wastes are taken for reclamation or disposal may also have the right to pursue legal actions to enforce compliance, to seek damages for contamination, or for personal injury or property damage.

Changes in environmental laws and regulations occur frequently, and any changes that result in delays or restrictions in permitting or development of projects or more stringent or costly construction, drilling, water management, or completion activities or waste handling, storage, transport, remediation or disposal, emission or discharge requirements could require significant expenditures by Avalon to attain and maintain compliance and may otherwise have a material adverse effect on the results of operations, competitive position or financial condition of Avalon. In addition, delays or restrictions in permitting or development of projects that reduce or temporarily or permanently halt the production of oil, natural gas and natural gas liquids at any of the Underlying Properties will reduce Trust distributions by reducing the amount of proceeds available for distribution.

29

Climate change laws and regulations restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil, natural gas and NGL produced from the Underlying Properties.

In 2009, the EPA published its findings that emissions of carbon dioxide, methane and certain other “greenhouse gases” (collectively, “GHGs”) present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. The EPA has taken a number of steps aimed at gathering information about, and reducing the emissions of, GHGs from industrial sources, including oil and natural gas sources. The EPA has adopted rules requiring the reporting of GHG emissions from oil, natural gas and NGL production and processing facilities on an annual basis, as well as reporting GHG emissions from gathering and boosting systems, oil well completions and workovers using hydraulic fracturing. The EPA has also adopted and implemented regulations under existing provisions of the CAA that, among other things, establish Prevention of Significant Deterioration (“PSD”) construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet “best available control technology” standards that typically are established by the states. This rule could adversely affect Avalon’s operations upon the Underlying Properties and restrict or delay its ability to obtain air permits for new or modified facilities that exceed GHG emission thresholds. In June 2016, the EPA published a final rule adopting New Source Performance Standards (“NSPS”) for new, modified, or reconstructed oil and gas facilities that require control of the GHG methane from affected facilities, including requirements to find and repair fugitive leaks of methane emissions at well sites (“Methane Rule”). Following the 2016 presidential election and change in administrations, in 2017 the EPA proposed to delay implementation of the Methane Rule, and also convened a reconsideration proceeding that resulted in two 2018 rulemaking projects aimed at rolling back certain Methane Rule requirements. These actions, like the Methane Rule itself, have been (or are likely to be) challenged in courts. The ultimate fate of the Methane Rule requirements is unclear. Nevertheless, regulations promulgated under the CAA may require Avalon to incur development expenses to install and utilize specific equipment, technologies, or work practices to control emissions from its operations.

In addition, in November 2016, the U.S. Department of the Interior Bureau of Land Management (“BLM”) issued final rules to reduce methane emissions from venting, flaring, and leaks during oil and gas operations on federal and tribal lands that are substantially similar to the EPA’s Methane Rule. However, on December 8, 2017, the BLM published a final rule to temporarily suspend or delay certain requirements contained in the November 2016 final rule until January 17, 2019, including those requirements relating to venting, flaring and leakage from oil and gas production activities. Further, in September 2018, the BLM published a final rule to revise or rescind certain provisions of the 2016 rule. While the future implementation of the EPA and BLM rules aimed at controlling GHG emissions from oil and natural gas sources remains uncertain, future federal GHG regulations for the oil and gas industry remain a possibility given the long-term trend towards increasing regulation. Moreover, several states have already adopted rules requiring operators of both new and existing sources to develop and implement a LDAR program and to install devices on certain equipment to capture 95 percent of methane emissions. Compliance with these rules could require Avalon to purchase pollution control equipment and optical gas imaging equipment for LDAR inspections, and to hire additional personnel to assist with inspection and reporting requirements.

A number of state and regional efforts also are aimed at tracking and/or reducing GHG emissions by means of cap-and-trade programs that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. On an international level, the United States is one of almost 200 nations that in December 2015 entered into the Paris Agreement, which calls for countries to set their own GHG emissions targets and maintain transparency regarding the measures each country will use to achieve its GHG emissions targets. However, the Paris Agreement does not impose any binding obligations on the United States. Moreover, in June 2017, President Trump announced that the United States would withdraw from the Paris Agreement but may enter into a future international agreement related to GHGs. In August 2017, the U.S. State Department officially informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. Such withdrawal has not yet been finalized, and whether the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time. Further, several states and local governments remain committed to the principles of the Paris Agreement in their effectuation of policy and regulations. It is not possible at this time to predict how or when the United States might impose restrictions on GHGs as a result of the Paris Agreement.

The adoption and implementation of any laws or regulations imposing reporting obligations on, or limiting emissions of GHGs from, the equipment and operations of Avalon or other operators of the Underlying Properties could require additional expenditures to monitor, report and potentially reduce emissions of GHGs associated with their operations or could adversely affect demand for the oil, natural gas and NGL produced from the Underlying Properties. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and gas will continue to represent a substantial percentage of global energy use over that time. Finally, to the extent increasing concentrations of GHGs in the

Earth's atmosphere may produce climate changes that could have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events, such events could have a material adverse effect on the Underlying Properties, and potentially subject the Underlying Properties and the operations of Avalon or other operators of the Underlying Properties to greater regulation. The occurrence of any of these events that reduce or temporarily or permanently halt the production of oil, natural gas and natural gas liquids at any of the Underlying Properties will reduce Trust distributions by reducing the amount of proceeds available for distribution.

The Trust is subject to the requirements of the Sarbanes-Oxley Act of 2002, which may impose cost and operating challenges on it.

The Trust is subject to certain of the requirements of the Sarbanes-Oxley Act of 2002 which requires, among other things, maintenance by the Trust of, and reports regarding the effectiveness of, a system of internal control over financial reporting. Complying with these requirements may pose operational challenges and may cause the Trust to incur unanticipated expenses. Any failure by the Trust to comply with these requirements could lead to a loss of public confidence in the Trust's internal controls and in the accuracy of the Trust's publicly reported results.

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

Avalon relies on information technology ("IT") systems and networks in connection with its business activities, including certain of its exploration, development and production activities. Avalon relies on digital technology, including information systems and related infrastructure, as well as cloud applications and services, to, among other things, estimate quantities of oil, natural gas and NGL reserves, analyze seismic and drilling information, process and record financial and operating data and communicate with employees and third parties. As dependence on digital technologies has increased in the oil and gas industry, cyber incidents, including deliberate attacks and attempts to gain unauthorized access to computer systems and networks, have increased in frequency and sophistication. These threats pose a risk to the security of Avalon's systems and networks, the confidentiality, availability and integrity of its data and the physical security of its employees and assets. Avalon has experienced, and expects to continue to experience, attempts from hackers and other third parties to gain unauthorized access to its IT systems and networks. Avalon may not be successful in preventing cyber-attacks or mitigating their effect. Any cyber-attack could have a material adverse effect on Avalon's reputation, competitive position, business, financial condition and results of operations, and could have a material adverse effect on the Trust. Cyber-attacks or security breaches also could result in litigation or regulatory action, as well as significant additional expense to Avalon to implement further data protection measures.

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

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

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

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

Legislation or regulatory initiatives intended to address seismic activity are restricting and could further restrict Avalon's ability and the ability of other operators of the Underlying Properties to dispose of saltwater produced alongside hydrocarbons.

Large volumes of saltwater produced alongside Avalon's and other operators' oil, natural gas and NGL on the Underlying Properties in connection with drilling and production operations are disposed of pursuant to permits issued by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities.

Furthermore, in response to recent seismic events near underground disposal wells used for the disposal by injection of produced water resulting from oil and natural gas activities, federal and some state agencies are investigating whether such wells have caused increased seismic activity, and some states have restricted, suspended or shut down the use of such disposal wells. For example, in October 2014, the Texas Railroad Commission, or TRC, published a new rule governing permitting or re-permitting of disposal wells that would require, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If the permittee or an applicant of a disposal well permit fails to demonstrate that the saltwater or other fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the TRC may deny, modify, suspend or terminate the permit application or existing operating permit for that well. Evaluation of seismic incidents and whether or to what extent those events are induced by the injection of saltwater into disposal wells continues to evolve, as governmental authorities consider new and/or past seismic incidents in areas where salt water disposal activities occur or are proposed to be performed. The adoption of any new laws, regulations, or directives that restrict Avalon's ability to dispose of saltwater generated by production and development activities on the Underlying Properties, whether by plugging back the depths of disposal wells, reducing the volume of salt water disposed in such wells, restricting disposal well locations or otherwise, or by requiring Avalon to shut down disposal wells, which could negatively affect the economic lives of the Underlying Properties and have a material adverse effect on the Trust.

Tax Risks Related to the Units

The Trust's tax treatment depends on its status as a partnership for U.S. federal income tax purposes. If the U.S. Internal Revenue Service ("IRS") were to treat the Trust as a corporation for U.S. federal income tax purposes, then its cash available for distribution to unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in the Trust units depends largely on the Trust being treated as a partnership for U.S. federal income tax purposes. The Trust has not requested, and does not plan to request, a ruling from the IRS, on this or any other tax matter affecting it.

It is possible in certain circumstances for a publicly traded trust otherwise treated as a partnership, such as the Trust, to be treated as a corporation for U.S. federal income tax purposes. In addition, a change in current law could cause the Trust to be treated as a corporation for U.S. federal income tax purposes or otherwise subject it to federal taxation as an entity.

If the Trust were treated as a corporation for U.S. federal income tax purposes, it would pay federal income tax on its taxable income at the corporate tax rate, which after December 31, 2017 is a maximum of 21%, and likely would be required to also pay state income tax on its taxable income at the corporate tax rate of such state. Distributions to unitholders generally would be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to unitholders. Because additional tax would be imposed upon the Trust as a corporation, its cash available for distribution to unitholders would be substantially reduced. Therefore, treatment of the Trust as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the Trust unitholders, likely causing a substantial reduction in the value of the Trust units.

If the Trust were subjected to a material amount of additional entity-level taxation by individual states, it would reduce the Trust's cash available for distribution to unitholders.

The Trust is required to pay Texas franchise tax each year at a maximum effective rate (subject to changes in the statutory rate) of 0.525% of its gross income apportioned to Texas. This rate of tax is subject to change by new legislation at any time.

Changes in current state law may subject the Trust to additional entity-level taxation by individual states. Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation.

32

Upon examination, a state may contest any of the tax positions the Trust has taken. Audit adjustments to an entity-level state tax, such as Texas franchise tax (including any applicable penalties and interest) are collected directly from the Trust upon completion of the examination.

Additional imposition of such taxes may substantially reduce the cash available for distribution to unitholders and, therefore, negatively impact the value of an investment in Trust units.

Recently enacted tax legislation significantly may impact the taxation of our income and our unitholders.

The recently enacted Tax Cut and Jobs Act ("TCJA") provides the most substantial tax reform in over thirty years. In general, the TCJA lowers tax rates, eliminates or limits numerous deductions and other tax benefits, and significantly changes international tax rules. Given the complexity of the TCJA and the significant changes to prior tax law, its impact and effect on the Trust and unitholders in respect of income and loss of the Trust is uncertain.

The foregoing is not a complete summary of all of the changes in law that may apply to or impact the Trust or a unitholder with respect to income of the Trust (or otherwise), unitholders strongly are urged to consult with their own tax advisors to determine how they might be affected by the TCJA, both generally and specifically with respect to their ownership of trust units.

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

Current law may change so as to cause the Trust to be treated as a corporation for U.S. federal income tax purposes or otherwise subject the Trust to entity-level taxation. Specifically, the present U.S. federal income tax treatment of publicly traded partnerships, including the Trust, or an investment in the Trust units may be modified by administrative, legislative or judicial interpretation at any time. For example, from time to time, members of the U.S. Congress propose and consider substantive changes to existing federal income tax laws that could affect publicly traded partnerships. Such proposals, if adopted, could eliminate the qualifying income exception for publicly traded partnerships deriving qualifying income from activities relating to fossil fuels thus treating such partnerships as corporations. We currently rely upon this qualifying income exemption for our treatment of the Trust as a partnership for U.S. federal income tax purposes, which was not modified under the TCJA (see "—Recently enacted tax legislation significantly may impact the taxation of our income and our unitholders."

Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals ultimately will be enacted. Any such changes could have a material adverse effect on the value of the Trust units.

The Trust has adopted and may continue to adopt positions that may not conform to all aspects of existing Treasury Regulations. If the IRS contests the tax positions the Trust takes, the value of the Trust units may be adversely affected, the cost of any IRS contest will reduce the Trust's cash available for distribution and income, gains, losses and deductions may be reallocated among Trust unitholders. Recently enacted federal legislation alters the procedures for assessing and collecting income taxes due for taxable years beginning after December 31, 2017, in a manner that could substantially reduce cash available for distribution to Trust unitholders.

If the IRS contests any of the U.S. federal income tax positions the Trust takes or has taken, the value of the Trust units may be adversely affected, because the cost of any IRS contest will reduce the Trust's cash available for distribution and income, gain, loss and deduction may be reallocated among Trust unitholders. For example, the Trust generally prorates its items of income, gain, loss and deduction between transferors and transferees of the Trust units each quarter based upon the record ownership of the Trust units on the quarterly record date in such quarter, instead of on the basis of the date a particular Trust unit is transferred. Although simplifying conventions are contemplated by the Internal Revenue Code, and most publicly traded partnerships use similar simplifying conventions, the use of these methods may not be permitted under existing Treasury Regulations, and, accordingly, Avalon’s counsel is unable to opine as to the validity of this method. If the IRS were to challenge the Trust’s proration method, the Trust may be required to change its allocation of items of income, gain, loss and deduction among the Trust unitholders and the costs to the Trust of implementing and reporting under any such changed method may be significant.

The Trust has not requested a ruling from the IRS with respect to its treatment as a partnership for U.S. federal income tax purposes or any other matter affecting the Trust. The IRS may adopt positions that differ from the conclusions of Avalon’s counsel or from the positions the Trust takes. It may be necessary to resort to administrative or court proceedings to attempt to sustain some or all of the conclusions of Avalon’s counsel or the positions the Trust takes. A court may not agree with some or all of the conclusions of Avalon's counsel or positions the Trust takes. Any contest with the IRS may materially and adversely impact the market for the Trust units and the price at which they trade. In addition, the Trust's costs of any contest with the IRS will be borne indirectly by the Trust unitholders, because the costs will reduce the Trust's cash available for distribution.

Recently enacted federal legislation applicable to the Trust for taxable years beginning after December 31, 2017 alters the procedures for auditing large partnerships and also alters the procedures for assessing and collecting income taxes due (including applicable penalties and interest) as a result of an audit. Unless the Trust is eligible to (and chooses to) elect to issue revised Schedules K-1 to Trust unitholders with respect to an audited and adjusted return, the IRS may assess and collect income taxes (including any applicable penalties and interest) directly from the Trust in the year in which the audit is completed under the new rules, which effectively would impose an entity level tax on the Trust. If the Trust is required to pay income taxes, penalties and interest as the result of audit adjustments, cash available for distribution to Trust unitholders may be substantially reduced. In addition, because payment would be due for the taxable year in which the audit is completed, Trust unitholders during that taxable year would bear the expense of the adjustment even if they were not Trust unitholders during the audited taxable year.

Each unitholder is required to pay taxes on the unitholder's share of the Trust's income even if a unitholder does not receive cash distributions from the Trust equal to the unitholder's share of the Trust's taxable income.

Because the Trust unitholders are treated as partners to whom the Trust allocates taxable income that could be different in amount than the cash the Trust distributes, each unitholder may be required to pay any federal income taxes and, in some cases, state and local income taxes on the unitholder's share of the Trust's taxable income even if a unitholder does not receive cash distributions from the Trust equal to the unitholder's share of the Trust's taxable income or even equal to the actual tax liability that results from that income.

Tax gain or loss on the disposition of the Trust units could be more or less than expected.

If a unitholder sells its Trust units, the unitholder will recognize a gain or loss equal to the difference between the amount realized and the unitholder's tax basis in those Trust units. Because distributions in excess of a unitholder's allocable share of the Trust's net taxable income decrease the unitholder's adjusted tax basis in its Trust units, the amount, if any, of such prior excess distributions with respect to the Trust units unitholders sell will, in effect, become taxable income to unitholders if unitholders sell such Trust units at a price greater than the unitholder's tax basis in those Trust units, even if the price the unitholder receives is less than the unitholder's original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depletion recapture.

The ownership and disposition of Trust units by tax-exempt organizations and non-U.S. persons may result in adverse tax consequences to them.

Tax-Exempt Organizations. Employee benefit plans and most other organizations exempt from U.S. federal income tax including individual retirement accounts (known as IRAs) and other retirement plans are subject to U.S. federal income tax on unrelated business taxable income. Because all of the income of the Trust is expected to be royalty income, interest income, hedging income and gain from the sale of real property, none of which is expected to be unrelated business taxable income, any such organization exempt from U.S. federal income tax is not expected to be taxed on income generated by ownership of Trust units so long as neither the property held by the Trust nor the Trust units are debt-financed property within the meaning of Section 514(b) of the Internal Revenue Code. However, such investors should consult their own tax advisors as to the proposed treatment of income from the Trust.

Non-U.S. Persons. Pursuant to Internal Revenue Code Section 1446, withholding tax on income effectively connected to a United States trade or business allocated to non-U.S. persons ("ECI") should be made at the highest marginal rate.

Under Internal Revenue Code Section 1441, withholding tax on fixed, determinable, annual, periodic income from United States sources allocated to non-U.S. persons should be made at 30% of gross income unless the rate is reduced by treaty. Nominees and brokers should withhold at the highest marginal rate on the distribution made to non-U.S. persons. The TCJA, discussed above, treats a non-U.S. holder's gain on the sale of Trust units as ECI to the extent such holder would have had ECI if the Trust had sold all of its assets at fair market value on the date of the exchange. The new legislation also requires the transferee of units to withhold 10% of the amount realized on the sale of exchange of units (generally, the purchase price) unless the transferor certifies that it is not a nonresident alien individual or foreign corporation.

The Trust treats each purchaser of Trust units as having the same economic attributes without regard to the actual Trust units purchased. The IRS may challenge this treatment, which could adversely affect the value of the Trust units.

Due to a number of factors, including the Trust's inability to match transferors and transferees of Trust units, the Trust may adopt positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely alter the tax effects of an investment in Trust units. It also could affect the timing of tax benefits or the amount of gain from a unitholder's sale of Trust units and could have a negative impact on the value of the Trust units or result in audit adjustments to a unitholder's tax returns.

The Trust prorates its items of income, gain, loss and deduction between transferors and transferees of the Trust units each quarter based upon the record ownership of the Trust units on the quarterly record date, in such quarter, instead of on the basis of the date a particular Trust unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among the Trust unitholders.

The Trust generally prorates its items of income, gain, loss and deduction between transferors and transferees of the Trust units based upon the record ownership of the Trust units on the quarterly record date in such quarter instead of on the basis of the date a particular Trust unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations, and, accordingly, Avalon's counsel is unable to opine as to the validity of this method. If the IRS were to challenge the Trust's proration method, the Trust may be required to change its allocation of items of income, gain, loss and deduction among the Trust unitholders and the costs to the Trust of implementing and reporting under any such changed method may be significant.

A Trust unitholder whose Trust units are loaned to a "short seller" to cover a short sale of Trust units may be considered as having disposed of those Trust units. If so, he would no longer be treated for tax purposes as a partner with respect to those Trust units during the period of the loan and may recognize gain or loss from the disposition.

Because a Trust unitholder whose Trust units are loaned to a "short seller" to cover a short sale of Trust units may be considered as having disposed of the loaned Trust units, he or she may no longer be treated for tax purposes as a partner with respect to those Trust units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of the Trust's income, gains, losses or deductions with respect to those Trust units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those Trust units could be fully taxable as ordinary income. Trust unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from loaning their Trust units.

The Trust may adopt certain valuation methodologies that may affect the income, gain, loss and deduction allocable to the Trust unitholders. The IRS may challenge this treatment, which could adversely affect the value of the Trust units.

The U.S. federal income tax consequences of the ownership and disposition of Trust units will depend in part on the Trust's estimates of the relative fair market values, and the initial tax basis of the Trust's assets. Although the Trust may from time to time consult with professional appraisers regarding valuation matters, the Trust will make many of the relative fair market value estimates itself. These estimates and determinations of basis are subject to challenge and will not be binding on the IRS or the courts. If the estimates of fair market value or basis are later found to be incorrect, the character and amount of items of income, gain, loss or deductions previously reported by Trust unitholders might change, and Trust unitholders might be required to adjust their tax liability for prior years and incur interest and penalties with respect to those adjustments.

The availability and extent of percentage depletion deductions to the Trust unitholders for any taxable year is uncertain.

The payments received by the Trust with respect to the perpetual portion of the Royalty Interests are treated as mineral royalty interests for U.S. federal income tax purposes and taxable as ordinary income. Trust unitholders are entitled to deductions for the greater of either cost depletion or (if otherwise allowable) percentage depletion with respect to such income. Although the Internal Revenue Code requires each Trust unitholder to compute his own depletion allowance and maintain records of his share of the adjusted tax basis of the underlying royalty interest for depletion and other purposes, the Trust will furnish each of the Trust unitholders with information relating to this computation for U.S. federal income tax purposes. Each Trust unitholder, however, remains responsible for calculating his own depletion allowance and maintaining records of his share of the adjusted tax basis of the perpetual royalties for depletion and other purposes. The rules with respect to this depletion allowance are complex and must be computed separately by each Trust unitholder and not by the Trust for each oil or natural gas property. As a result, the availability or extent of percentage depletion deductions to the Trust unitholders for any taxable year is uncertain.

Item 1B. Unresolved Staff Comments

35

None.

Item 2. Properties

Information regarding the Trust’s properties is included in Item 1 of this report. Also, refer to Note 9 to the financial statements included in Item 8 of this report.

Item 3. Legal Proceedings

None.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

The Trust units are listed on the New York Stock Exchange under the symbol “PER.” On March 7, 2019, there were nine record unitholders of the Trust units.

Distributions

The Trust makes quarterly cash distributions of substantially all of its cash receipts, after deducting amounts for the Trust’s administrative expenses, property tax and Texas franchise tax and cash reserves withheld by the Trustee, on or about the 60th day following the completion of each quarter.

Equity Compensation Plans

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

Recent Sales of Unregistered Securities

None.

Purchases of Securities

There were no purchases of Trust units by the Trust or any affiliated purchaser during the fourth quarter of 2018.

Item 6. Selected Financial Data

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

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

Introduction

The following discussion and analysis is intended to help the reader understand the Trust's business, financial condition, results of operations, liquidity and capital resources. This discussion and analysis should be read in conjunction with other sections of this report, including: "Business" in Item 1 and "Financial Statements and Supplementary Data" in Item 8. The discussion and analysis relate to the following subjects:

•Recent Developments

•Results of Trust Operations

36

•Liquidity and Capital Resources

•Critical Accounting Policies and Estimates

•Off-Balance Sheet Arrangements

Recent Developments

The following is a brief overview of certain matters discussed more thoroughly elsewhere in this report.

On November 1, 2018, SandRidge sold all of its interests in the Underlying Properties and all of its outstanding Trust units to Avalon (the "Sale Transaction"). In connection with the transaction, Avalon assumed all of SandRidge's obligations under the trust agreement and the administrative services agreement as of November 1, 2018. As part of the Sale Transaction, SandRidge and Avalon entered into a transition services agreement whereby SandRidge is providing certain transition services to Avalon, including trust administrative services, through March 31, 2019. These services include the preparation and filing of reports in accordance with applicable securities laws (including this report). The Trust expects to continue in the normal course without disruption to the unitholders, and the resulting sale is not expected to have an impact on the operations and future distributions of the Trust.

The Trust's reserves and quarterly cash distributions are highly dependent upon the prices realized from the sale of oil, natural gas and NGL. The markets for these commodities are volatile and experienced substantial fluctuations during 2018, with oil, natural gas and NGL prices declining significantly in the fourth quarter. A buildup in inventories, lower global demand, or other factors could cause prices for U.S. oil, natural gas and NGL to weaken further.

Results of Trust Operations

Results of the Trust for the Years Ended December 31, 2018 and 2017

The primary factors affecting the Trust's revenues and costs are the quantity of oil, natural gas and NGL production attributable to the Royalty Interests and the prices received for such production. Royalty income, post-production expenses and certain taxes are recorded on a cash basis when the Trust receives net revenue distributions from SandRidge (or, in future periods, Avalon). Information regarding the Trust's revenues, expenses, production and pricing for the years ended December 31, 2018 and 2017 is presented below.

	Year Ended December 31,			
	2018 (1)		2017 (2)	
Production data				
Oil (MBbls)	485		584	
NGL (MBbls)	72		83	
Natural gas (MMcf)	227		281	
Combined equivalent volumes (MBoe)(3)	595		714	
Average daily combined equivalent volumes (MBoe/d)	1.6		2.0	
Well data				
Initial and Trust Development Wells producing - average	1,064		1,104	
Revenues (in thousands)				
Royalty income	$	29,857	$	28,799
Total revenue	$	29,857	$	28,799
Expenses (in thousands)				
Post-production expenses	$	46	$	58
Property taxes	1,559		2,223	
Production taxes	1,423		1,377	
Franchise taxes	47		47	
Trust administrative expenses	1,402		1,494	
Cash reserves withheld (used), net of amounts (used) withheld for current Trust expenses	54		(740)	
Total expenses	$	4,531	$	4,459
Distributable income available	$	25,326	$	24,340

to unitholders				
Average prices				
Oil (per Bbl)	$	56.96	$	45.44
NGL (per Bbl)	$	24.16	$	19.27
Combined oil and NGL (per Bbl)	$	52.70	$	42.18
Natural gas (per Mcf)	$	1.91	$	2.30
Combined equivalent (per Boe)	$	50.08	$	40.33
Average prices - including impact of post-production expenses				
Natural gas (per Mcf)	$	1.71	$	2.10
Combined equivalent (per Boe)	$	50.00	$	40.24
Expenses (per Boe)				
Post-production	$	0.08	$	0.08
Production taxes	$	2.39	$	1.93

(1) Production volumes and related revenues and expenses for the year ended December 31, 2018 (included in SandRidge's 2018 net revenue distributions to the Trust) represent oil, natural gas and NGL production from September 1, 2017 to August 31, 2018.
(2) Production volumes and related revenues and expenses for the year ended December 31, 2017 (included in SandRidge's 2017 net revenue distributions to the Trust) represent oil, natural gas and NGL production from September 1, 2016 to August 31, 2017.
(3) Barrel of oil equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, which approximates the relative energy content of oil as compared to natural gas.

Comparison of Results of the Trust for the Years Ended December 31, 2018 and 2017

Revenues

Royalty Income. Royalty income is a function of production volumes sold attributable to the Royalty Interests and associated prices received. Royalty income received during the year ended December 31, 2018 totaled $29.9 million compared to $28.8 million received during the year ended December 31, 2017. The approximately $1.1 million increase in royalty income consisted of approximately $5.9 million attributable to an increase in prices received, partially offset by approximately $4.8 million attributable to a decrease in total volumes produced. The average number of producing wells decreased by 40 during the year ended December 31, 2018 compared to the year ended December 31, 2017.

38

Expenses

Post-Production Expenses. The Trust bears post-production expenses attributable to production attributable to the Royalty Interests. Post-production expenses generally consist of costs incurred to gather, store, compress, transport, process, treat, dehydrate and market, as applicable, the oil, natural gas and NGL produced from the underlying Properties. Post-production expenses for the year ended December 31, 2018 decreased to approximately $46,000 from approximately $58,000 for the year ended December 31, 2017 primarily as a result of the decrease in production.

Property Taxes. Property taxes paid during the year ended December 31, 2018 totaled approximately $1.6 million compared to approximately $2.2 million for the year ended December 31, 2017. The total payment made related to 2018 property taxes was approximately $1.6 million (paid in October 2018 and December 2018) The total payment made related to 2017 property taxes was approximately $1.5 million (paid in October 2017 and December 2017). Approximately $0.8 million was paid in January 2017 relating to 2016 property taxes.

Production Taxes. Production taxes are calculated as a percentage of oil, natural gas and NGL revenues, excluding the effects of derivative settlements and net of any applicable tax credits. Production taxes for the year ended December 31, 2018 totaled $1.4 million, or $2.39 per Boe, and were approximately 4.8% of royalty income. Production taxes for the year ended December 31, 2017 totaled $1.4 million, or $1.93 per Boe, and were approximately 4.8% of royalty income.

Texas Franchise Tax. The Trust paid its Texas franchise tax for the year ended December 31, 2017 of approximately $0.1 million, or approximately 0.2% of 2017 royalty income, during the year ended December 31, 2018. The Trust’s estimated Texas franchise tax for the year ended December 31, 2018 of approximately $0.1 million, or approximately 0.2% of 2018 royalty income, is expected to be paid during the year ending December 31, 2019.

Distributable Income

Distributable income for the year ended December 31, 2018 was $25.3 million, which included a net addition of approximately $0.1 million to the cash reserve for the payment of future Trust expenses reflecting approximately $3.1 million withheld in aggregate from 2018 cash distributions to unitholders partially offset by approximately $3.0 million used to pay Trust expenses during the period. Distributable income for the year ended December 31, 2017 was $24.4 million, which included a net reduction to the cash reserve for the payment of future Trust expenses of approximately $0.7 million reflecting approximately $3.7 million used to pay Trust expenses during the period partially offset by approximately $3.0 million withheld in aggregate from 2017 cash distributions to unitholders.

Liquidity and Capital Resources

The Trust has no source of liquidity or capital resources other than cash flow generated from the Royalty Interests and borrowings as needed to fund administrative expenses, including any amounts borrowed under Avalon’s loan commitment described in Note 5 to the financial statements contained in Item 8 of this report. The Trust’s primary uses of cash are distributions to Trust unitholders, payment of Trust administrative expenses, including any reserves established by the Trustee for future liabilities, payment of applicable taxes, and payment of expense reimbursements to Avalon for out-of-pocket expenses incurred on behalf of the Trust. The Trust is not obligated to pay any operating expenses or capital costs related to the wells.

Administrative expenses include payments to the Trustee and the Delaware Trustee as well as a quarterly fee of $75,000 to SandRidge (or, following the Sale Transaction, to Avalon) pursuant to the administrative services agreement. Each quarter, the Trustee determines the amount of funds available for distribution. Available funds are the excess cash, if any, received by the Trust from the sale of production attributable to the Royalty Interests that quarter, over the Trust’s expenses for the quarter. If at any time the Trust’s cash on hand (including available cash reserves) is not sufficient to pay the Trust’s ordinary course administrative expenses as they become due, the Trust may borrow funds from the Trustee or other lenders, including Avalon, to pay such expenses. The Trustee has not loaned and does not intend to lend funds to the Trust. If such funds are borrowed, no further distributions will be made to Trust unitholders (except in respect of any previously determined quarterly distribution amount) until the borrowed funds have been repaid. Where Avalon loans such funds to the Trust, Avalon may permit the Trust to make distributions prior to Avalon being repaid. There was no such loan outstanding at either December 31, 2018 or 2017.

The Trustee intends to withhold the greater of $190,000 or 3.5% of the funds otherwise available for distribution to Trust unitholders each quarter to gradually increase cash reserves by a total of approximately $2,275,000, commencing with the

39

distribution payable in the first quarter of 2019. In February 2019, the Trustee withheld $190,000 from the funds otherwise available for distribution to Trust unitholders.

Following the closing of the Sale Transaction, the Trust is highly dependent on Avalon for multiple services, including the operation of the Trust wells, remittance of net proceeds to the Trust from the sale of hydrocarbon production attributable to the Underlying Properties, administrative services such as accounting, tax preparation, bookkeeping and reporting services performed on behalf of the Trust, and potentially for loans to pay Trust administrative expenses. Avalon is a newly formed company with no operating history. Its activities to date have been limited to organizational efforts, assembling a management team, raising capital, researching and developing its business plan, and completing the Sale Transaction. The ability to operate the Underlying Properties depends on Avalon's future financial condition and economic performance, access to capital, and other factors, many of which are out of Avalon's control.

Trust Distributions to Unitholders. During the years ended December 31, 2018 and 2017, the Trust's distributions to unitholders were as follows:

	Covered Production Period	Date Declared	Date Paid	Total Distribution Paid (in millions)	
Calendar Quarter 2018					
First Quarter	September 1, 2017 - November 30, 2017	January 25, 2018	February 23, 2018	$	5.9
Second Quarter	December 1, 2017 - February 28, 2018	April 26, 2018	May 25, 2018	$	6.6
Third Quarter	March 1, 2018 - May 31, 2018	July 26, 2018	August 24, 2018	$	6.8
Fourth Quarter	June 1, 2018 - August 31, 2018	October 25, 2018	November 23, 2018	$	6.0
Calendar Quarter 2017					
First Quarter	September 1, 2016 - November 30, 2016	January 26, 2017	February 24, 2017	$	6.3
Second Quarter	December 1, 2016 - February 28, 2017	April 27, 2017	May 26, 2017	$	6.8
Third Quarter	March 1, 2017 - May 31, 2017	July 27, 2017	August 25, 2017	$	6.2
Fourth Quarter	June 1, 2017 - August 31, 2017	October 26, 2017	November 24, 2017	$	5.0

On February 22, 2019, the Trust paid a cash distribution of $0.095 per Trust unit covering production for the three-month period from September 1, 2018 to November 30, 2018. The distribution totaled $5.0 million and was made to Trust unitholders of record as of February 8, 2019.

Continued low oil, natural gas, and NGL prices will reduce proceeds to which the Trust is entitled and may ultimately reduce the amount of oil, natural gas and NGL that is economic to produce from the Underlying Properties. As the Trust cannot acquire or cause additional wells to be drilled on its behalf, the production from the Underlying Properties attributable to the Royalty Interests is expected to decline each quarter during the remainder of the Trust's life.

Contractual Obligations. Pursuant to the terms of the administrative services agreement, the Trust is obligated to pay Avalon (as assignee of SandRidge) an annual administrative services fee of $300,000 for accounting, tax preparation, bookkeeping, and informational services to be performed on behalf of the Trust for the remaining life of the Trust. Pursuant to the trust agreement, the Trust pays the Trustee an annual administrative fee, which until April 1, 2017 was $150,000. The annual fee can be adjusted for inflation by no more than 3% in any year through 2030. The annual administrative fee, which was adjusted for inflation in July 2018, currently is approximately $157,000. In addition, under the trust agreement the Trust is obligated to pay the Delaware Trustee an annual fee of $2,400 throughout the life of the Trust.

Critical Accounting Policies and Estimates

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

40

Basis of Accounting. The financial statements of the Trust differ from financial statements prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") as the Trust records revenues when cash is received (rather than when earned) and expenses when paid (rather than when incurred) and may also establish cash reserves for contingencies, which would not be accrued in financial statements prepared in accordance with GAAP. This comprehensive basis of accounting other than GAAP corresponds to the accounting permitted for royalty trusts by the SEC as specified by Staff Accounting Bulletin Topic 12:E, Financial Statements of Royalty Trusts. Amortization of investment in royalty interests, calculated on a unit-of-production basis, and any impairment are charged directly to trust corpus. Distributions to unitholders are recorded when declared. Because the Trust's financial statements are prepared on a modified cash basis, most accounting pronouncements are not applicable to the Trust's financial statements.

Proved Reserves. The proved oil, natural gas and NGL reserves for the Royalty Interests are estimated by independent petroleum engineers. Estimates of proved reserves are based on the quantities of oil, natural gas and NGL that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions, however, there are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future revenues, rates of production and timing of development expenditures, including many factors beyond the Trust's control. Estimating reserves is very complex and relies on assumptions and subjective interpretations of available geologic, geophysical, engineering and production data, and the accuracy of reserve estimates is a function of the quality and quantity of available data, engineering and geological interpretation and judgment. In addition, as a result of volatility of changing market conditions, commodity prices will vary from period to period, causing estimates of proved reserves to vary, as well as causing estimates of future net revenues to vary. Estimates of proved reserves are key components of the Trust's most significant financial estimates as discussed further below.

Amortization of Investment in Royalty Interests. Amortization of investment in royalty interests is calculated on a units-of-production basis, whereby the Trust's cost basis is divided by the proved reserves attributable to the Royalty Interests to derive an amortization rate per reserve unit. The rate used to record amortization is dependent upon the estimate of total proved reserves for the Royalty Interests, which incorporates various assumptions and future projections. If the estimates of total proved reserves decline significantly, the rate at which the Trust records amortization would increase, reducing trust corpus. Such a decline in reserves may result from lower commodity prices, which may make it uneconomic for Avalon to produce from the Underlying Properties, or from other factors, including changes to estimates for other reasons. Changes in reserve quantity estimates are dependent on future economic and operational conditions and cannot be predicted.

Impairment of Investment in Royalty Interests. The investment in royalty interests is assessed to determine whether net capitalized cost is impaired whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Potential impairments of the investment in royalty interests are determined by comparing the net capitalized costs of investment in royalty interests to undiscounted future net revenues attributable to the Trust's interest in the proved oil, natural gas and NGL reserves of the Underlying Properties. The Trust provides a write-down to the extent that the net capitalized costs exceed the fair value of the Royalty Interests, which is determined using future cash flows of the oil, natural gas and NGL reserves attributable to the Royalty Interests, discounted at a rate based upon the weighted average cost of capital of publicly traded royalty trusts. Different pricing assumptions or discount rates could result in a different calculated impairment. No impairments were recorded in 2018 or 2017. Material write-downs in subsequent periods may occur if commodity prices decline.

Refer to Note 2 to the financial statements included in Item 8 of this report for the Trust's significant accounting policies.

Off-balance sheet arrangements

As of December 31, 2018, the Trust had no off-balance sheet arrangements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

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

Item 8. Financial Statements and Supplementary Data

The Trust’s financial statements required by this item are included in this report beginning on page F-1.

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

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures.

The Trustee conducted an evaluation of the effectiveness of the design and operation of the Trust's disclosure controls and procedures pursuant to Exchange Act Rules 13a-15(a) and 15d-15(a) as of the end of the period covered by this report. Based on this evaluation, Sarah Newell, as Trust Officer, has concluded that the disclosure controls and procedures of the Trust are effective as of December 31, 2018 to provide reasonable assurance that the information required to be disclosed by the Trust in its reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and such information is accumulated and communicated, as appropriate to allow timely decisions regarding required disclosure. In its evaluation of disclosure controls and procedures, the Trustee has relied, to the extent considered reasonable, on information provided by SandRidge with respect to the periods covered by this report.

Due to the nature of the Trust as a passive entity and in light of the contractual arrangements pursuant to which the Trust was created, including the provisions of (i) the trust agreement, (ii) the administrative services agreement, (iii) the development agreement and (iv) the conveyances granting the Royalty Interests, the Trustee's disclosure controls and procedures related to the Trust necessarily rely on (A) information provided by SandRidge, including information relating to results of operations, the costs and revenues attributable to the Royalty Interests and other operating and historical data, plans for future operating and capital expenditures, reserve information, information relating to projected production, and other information relating to the status and results of operations of the Underlying Properties and the Royalty Interests, and (B) conclusions and reports regarding reserves by the Trust's independent reserve engineers.

Trustee's Report on Internal Control over Financial Reporting and Report of Independent Registered Public Accounting Firm.

The information required to be furnished pursuant to this item is set forth below and in the "Report of Independent Registered Public Accounting Firm" in Item 8 of this annual report.

The Trustee is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) promulgated under the Exchange Act. The Trustee conducted an evaluation of the effectiveness of the Trust's internal control over financial reporting based on the criteria established in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the Trustee's evaluation under the framework in Internal Control-Integrated Framework (2013), the Trustee concluded that the Trust's internal control over financial reporting was effective as of December 31, 2018. The effectiveness of the Trust's internal control over financial reporting as of December 31, 2018 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report, which is included in this annual report.

According to the Internal Control-Integrated Framework (2013), a registrant's internal control over financial reporting is a process designed by or under the supervision of, its principal executive officer and principal financial officer, or persons performing similar functions, and effected by the registrant's board of directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A registrant's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the registrant; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the registrant are being made only in accordance with authorizations of management and directors of the registrant; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the registrant'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.

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

42

materially affect, the Trust's internal control over financial reporting. The Trustee notes for purposes of clarification that it has no authority over, has not evaluated and makes no statement concerning, the internal control over financial reporting of SandRidge or Avalon.

Item 9B. Other Information

None.

43

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The Trust has no directors or executive officers. The Trustee is a corporate trustee that may be removed by the affirmative vote of the holders of not less than a majority of the outstanding Trust Units, excluding Trust Units held by SandRidge and its affiliates, at a special meeting of the Trust unitholders at which a quorum is present.

Section 16(a) Beneficial Ownership Reporting Compliance

The Trust has no directors or officers. Accordingly, only holders of more than 10% of the Trust Units are required to file with the SEC initial reports of ownership of Trust units and reports of changes in such ownership pursuant to Section 16 under the Exchange Act. Based solely on a review of these reports, the Trustee is not aware of any person having failed to file on a timely basis the reports required by Section 16(a) of the Exchange Act during the most recent fiscal year or prior fiscal years. In making this statement, the Trustee has relied upon examination of the copies of Forms 3, 4 and 5, to the extent there were any, provided to the Trust.

Audit Committee and Nominating Committee

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

Code of Ethics

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

Item 11. Executive Compensation

During the years ended December 31, 2018 and 2017, the Trustee and the Delaware Trustee received administrative fees from the Trust pursuant to the trust agreement. See the disclosures in the section entitled “Liquidity and Capital Resources – Contractual Obligations” in Item 7 of this report for the amounts of such compensation. The Trust does not have any executive officers, directors or employees. Because the Trust does not have a board of directors, it does not have a compensation committee.

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

(a) Security Ownership of Certain Beneficial Owners.

The following table sets forth certain information regarding the beneficial ownership of the Trust Units as of March 7, 2019 by each person who, to the Trustee’s knowledge, beneficially owns more than 5% of the outstanding Trust units.

Name and Address of Beneficial Owner	Title of Class	Amount and Nature of Beneficial Ownership	Percent of Class	
Avalon Energy, LLC 5000 Quorum Drive, Suite 205 Dallas, Texas 75254	Common units	13,125,000	25	%

(b) Security Ownership of Management.

Not applicable.

(c) Changes in Control.

In connection with the Sale Transaction, Avalon borrowed funds to pay a portion of the purchase price for the Underlying Properties and related assets to SandRidge. These funds were obtained as a part of a secured revolving credit agreement from a commercial bank. The collateral securing such revolving line of credit includes a pledge of its Trust Units. In the event Avalon defaults under such revolving credit agreement and does not cure such default within the time period provided in the applicable loan documents, the bank has the right to foreclose upon and take the Trust Units.

Item 13. Certain Relationships and Related Transactions and Director Independence

Avalon (as the assignee of SandRidge) and the Trust are parties to the administrative services agreement and the registration rights agreement. The Trust makes certain payments to Avalon, the Trustee and the Delaware Trustee, and previously made certain payments to SandRidge, pursuant to the trust agreement and the administrative services agreement. Descriptions of these agreements are included in “Business” in Item 1 of this report; in “Trustee’s Discussion and Analysis of Financial Condition and Results of Operations” in Item 7 of this report; and in Note 6 to the financial statements included in Item 8 of this report. In addition, the description of the initial public offering included in “Business” in Item 1 of this report is hereby incorporated by reference.

Director Independence

The Trust does not have a board of directors. Further, the Trust relies on an exemption from the director independence requirements of the New York Stock Exchange set forth in Rule 10A-3(c)(7) under the Exchange Act, applicable to listed issuers organized as trusts that do not have a board of directors.

Item 14. Principal Accounting Fees and Services

The Trust does not have an audit committee. Any pre-approval and approval of all services performed by the principal auditor or any other professional service firms and related fees are granted by the Trustee.

The following table presents fees for professional audit services rendered by PricewaterhouseCoopers LLP for the audit of the Trust’s financial statements for 2018 and 2017 and fees billed for other services rendered by PricewaterhouseCoopers LLP.

	2018		2017	
Audit fees(1)	$	255,000	$	255,000
Tax fees	310,050			350,000
Total fees	$	565,050	$	605,000

(1) Fees for audit services in 2018 and 2017 consisted of the audit of the Trust’s annual financial statements and reviews of the Trust’s quarterly financial statements.

PART IV

Item 15. Exhibits and Financial Statement Schedules

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

(1) Financial Statements

Reference is made to the Index to Financial Statements appearing on page F-1.

(2) Financial Statement Schedules

All financial statement schedules have been omitted because they are not applicable or the required information is presented in the financial statements or notes thereto.

(3) Exhibits

The exhibits below are filed or furnished herewith or incorporated herein by reference.

		Incorporated by Reference				
Exhibit No.	Exhibit Description	Form	SEC File No.	Exhibit	Filing Date	Filed or Furnished Herewith
3.1	Certificate of Trust of SandRidge Permian Trust	S-1	333-174492	3.1	05/25/2011	
3.2	Amended and Restated Trust Agreement, dated as of August 16, 2011, by and among SandRidge Energy, Inc., The Bank of New York Mellon Trust Company, N.A., and The Corporation Trust Company	8-K	001-35274	4.1	08/19/2011	
3.3	Amendment No. 1 to Amended and Restated Trust Agreement, dated June 18, 2012, by The Bank of New York Mellon Trust Company, N.A.	10-Q	001-35274	3.3	08/13/2012	
10.1	Perpetual Overriding Royalty Interest Conveyance (PDP), by and between SandRidge Exploration and Production, LLC and SandRidge Permian Trust	8-K	001-35274	10.3	08/19/2011	
10.2	Perpetual Overriding Royalty Interest Conveyance (Development), by and between SandRidge Exploration and	8-K	001-35274	10.4	08/19/2011	

	Production, LLC and SandRidge Permian Trust				
10.3	Assignment of Overriding Royalty Interest, by and between Mistmada Oil Company and SandRidge Permian Trust	8-K	001-35274	10.5	08/19/2011
10.4	Term Overriding Royalty Interest Conveyance (PDP), by and between SandRidge Exploration and Production, LLC and Mistmada Oil Company	8-K	001-35274	10.1	08/19/2011
10.5	Term Overriding Royalty Interest Conveyance (Development), by and between SandRidge Exploration and Production, LLC and Mistmada Oil Company	8-K	001-35274	10.2	08/19/2011
10.6	Administrative Services Agreement, by and between SandRidge Energy, Inc. and SandRidge Permian Trust	8-K	001-35274	10.6	08/19/2011
10.7	Deed of Trust, dated as of August 16, 2011, by and between SandRidge Exploration and Production, LLC and SandRidge Permian Trust	8-K	001-35274	10.9	08/19/2011
10.8	Registration Rights Agreement, dated	8-K	001-35274	10.1	08/19/2011

	as of August 16, 2011, by and between SandRidge Energy, Inc. and SandRidge Permian Trust					
10.9	Deed of Trust and Security Agreement from SandRidge Permian Trust, as Mortgagor, to Martha Wach, as Trustee, for the benefit of Wilmington Trust, National Association, as Collateral Agent, as Mortgagee, dated as of August 19, 2011	10-Q	001-35274	10.2	05/14/12	
10.1	Assignment, Assumption and Consent Agreement dated as of November 1, 2018, by and among SandRidge Energy, Inc., Avalon Energy, LLC, and SandRidge Permian Trust	8-K	001-35274	10.1	11/05/2018	
23.1	Consent of Netherland, Sewell & Associates, Inc.					*
31.1	Section 302 Certification					*
32.1	Section 906 Certification					*
99.1	Report of Netherland, Sewell & Associates, Inc.					*

Item 16. Form 10-K Summary

Not Applicable.

SIGNATURES

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

SANDRIDGE PERMIAN TRUST

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

By: /s/ Sarah Newell
Sarah Newell
Vice President

March 14, 2019

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

INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Unitholders of SandRidge Permian Trust and The Bank of New York Mellon Trust Company, N.A., as Trustee

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying statements of assets and trust corpus of SandRidge Permian Trust (the "Trust") as of December 31, 2018 and 2017, and the related statements of distributable income and of changes in trust corpus for the years then ended, including the related notes (collectively referred to as the "financial statements"). We also have audited the Trust's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the financial statements referred to above present fairly, in all material respects, the assets and trust corpus of the Trust as of December 31, 2018 and 2017, and its distributable income and its changes in trust corpus for the years then ended in conformity with the modified cash basis of accounting described in Note 2. Also in our opinion, the Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Trust's management is responsible for these financial statements, 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 appearing under Item 9A. Our responsibility is to express opinions on the Trust's financial statements and on the Trust's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Trust in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

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

Basis of Accounting

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

Definition and Limitations of Internal Control over Financial Reporting

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 generally accepted accounting principles. A trust's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the trust; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the trust are being made only in accordance with authorizations of management and the trustee; and (iii) 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.

/s/
PricewaterhouseCoopers
LLP

PricewaterhouseCoopers
LLP

Oklahoma City, Oklahoma
March 14, 2019

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

SANDRIDGE PERMIAN TRUST
STATEMENTS OF ASSETS AND TRUST CORPUS
(In thousands, except unit data)

	December 31, 2018	2017
ASSETS		
Cash and cash equivalents	$ 2,367	$ 2,292
Investment in royalty interests	549,831	549,831
Less: accumulated amortization and impairment	(436,973)	(425,955)
Net investment in royalty interests	112,858	123,876
Total assets	$ 115,225	$ 126,168
TRUST CORPUS		
Trust corpus, 52,500,000 common units issued and outstanding at December 31, 2018 and 2017	$ 115,225	$ 126,168

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

SANDRIDGE PERMIAN TRUST
STATEMENTS OF DISTRIBUTABLE INCOME
(In thousands, except unit and per unit data)

	Years Ended December 31,			
	2018			2017
Revenues				
Royalty income	$	29,857	$	28,799
Total revenues	29,857			28,799
Expenses				
Post-production expenses	46			58
Property taxes	1,559			2,223
Production taxes	1,423			1,377
Franchise taxes	47			47
Trust administrative expenses	1,402			1,494
Cash reserves withheld (used), net of amounts used (withheld) for current Trust expenses	54			(740)
Total expenses	4,531			4,459
Distributable income available to unitholders	25,326			24,340
Distributable income per unit	$	0.482	$	0.463

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

F-2

SANDRIDGE PERMIAN TRUST
STATEMENTS OF CHANGES IN TRUST CORPUS
(In thousands)

	Years Ended December 31,			
	2018			2017
Trust corpus, beginning of year	$	126,168	$	140,430
Amortization of investment in royalty interests	(11,018)			(13,502)
Net cash reserves withheld (used)	54			(740)
Distributable income	25,326			24,340
Distributions paid or payable to unitholders	(25,305)			(24,360)
Trust corpus, end of year	$	115,225	$	126,168

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

SANDRIDGE PERMIAN TRUST
NOTES TO FINANCIAL STATEMENTS

1. Organization of the Trust

Nature of Business. SandRidge Permian Trust (the “Trust”) is a statutory trust formed under the Delaware Statutory Trust Act pursuant to a trust agreement, as amended and restated, by and among SandRidge Energy, Inc. (“SandRidge”), as Trustor, The Bank of New York Mellon Trust Company, N.A., as Trustee (the “Trustee”), and The Corporation Trust Company, as Delaware Trustee (the “Delaware Trustee”) (such amended and restated trust agreement, as amended to date, the “trust agreement”).

The Trust holds Royalty Interests in specified oil and natural gas properties located in Andrews County, Texas (the “Underlying Properties”). The Royalty Interests were conveyed by SandRidge to the Trust concurrent with the initial public offering of the Trust’s common units (“Trust units”) in August 2011. As consideration for conveyance of the Royalty Interests, the Trust remitted the proceeds of the offering, along with 4,875,000 Trust units and 13,125,000 subordinated units of the Trust (“subordinated units”), to certain wholly owned subsidiaries of SandRidge.

Pursuant to a development agreement between the Trust and SandRidge, SandRidge was obligated to drill, or cause to be drilled, 888 development wells within an area of mutual interest (“AMI”) by March 31, 2016 (the “Trust Development Wells”). SandRidge fulfilled this obligation in November 2014, and, as a result, the subordinated units converted to Trust units in January 2016.

On November 1, 2018, SandRidge sold all of its interests in the Underlying Properties and all of its outstanding Trust units (the “Sale Transaction”) to Avalon Energy, LLC, a Texas limited liability company (“Avalon”). In connection with the transaction, Avalon assumed all of SandRidge’s obligations under the trust agreement and the administrative services agreement. At December 31, 2018, SandRidge owned 13,125,000 Trust units, or 25% of all Trust units.

The Trust is passive in nature and neither the Trust nor the Trustee has any control over, or responsibility for, any operating or capital costs related to the Underlying Properties. The business and affairs of the Trust are administered by the Trustee. The trust agreement generally limits the Trust’s business activities to owning the Royalty Interests and certain activities reasonably related thereto, including activities required or permitted by the terms of the conveyances related to the Royalty Interests.

Distributions. The Trust makes quarterly cash distributions of substantially all of its cash receipts, after deducting amounts for the Trust’s administrative expenses, property tax and Texas franchise tax and cash reserves withheld by the Trustee, on or about the 60th day following the completion of each quarter. Due to the timing of the payment of production proceeds to the Trust, each distribution covers production from a three-month period consisting of the first two months of the most recently ended quarter and the final month of the quarter preceding it.

Dissolution. The Trust will dissolve and begin to liquidate on March 31, 2031 (the “Termination Date”), unless sooner terminated in accordance with the provisions of the trust agreement noted below, and will soon thereafter wind up its affairs and terminate. At the Termination Date, 50% of the Royalty Interests will revert automatically to Avalon. The remaining 50% of the Royalty Interests will be sold at that time, with the net proceeds of the sale, as well as any remaining Trust cash reserves, distributed to the unitholders on a pro rata basis, subject to Avalon’s right of first refusal to purchase the Royalty Interests retained by the Trust at the Termination Date. The Trust will not dissolve until the Termination Date unless any of the following occurs: (a) the Trust sells all of the Royalty Interests; (b) cash available for distribution for any four consecutive quarters, on a cumulative basis, is less than $5.0 million; (c) Trust unitholders approve an earlier dissolution of the Trust; or (d) the Trust is judicially dissolved. In the case of any of the foregoing, the Trustee would then sell all of the Trust’s assets, either by private sale or public auction, and distribute the net proceeds of the sale to the Trust unitholders after payment, or reasonable provision for payment, of all Trust liabilities.

2. Significant Accounting Policies

Basis of Accounting. The financial statements of the Trust differ from financial statements prepared in accordance with accounting principles generally accepted in the United States of America (“GAAP”) as the Trust records revenues when cash is received (rather than when earned) and expenses when paid (rather than when incurred) and may also establish cash reserves for contingencies, which would not be accrued in financial statements prepared in accordance with GAAP. This comprehensive basis of accounting other than GAAP corresponds to the accounting permitted for royalty trusts by the Securities and Exchange Commission (“SEC”) as specified by Staff Accounting Bulletin Topic 12:E, Financial Statements of Royalty Trusts.

Amortization of investment in royalty interests, calculated on a unit-of-production basis, and any impairments are charged directly to trust corpus. Distributions to unitholders are recorded when declared.

Significant Accounting Policies. Most accounting pronouncements apply to entities whose financial statements are prepared in accordance with GAAP, which may require such entities to accrue or defer revenues and expenses in a period other than when such revenues are received or expenses are 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.

Use of Estimates. The preparation of financial statements requires the Trust to make estimates and assumptions that affect the reported amounts of assets and trust corpus and the reported amounts of revenues and expenses during the reporting period. Significant estimates that impact the Trust’s financial statements include estimates of proved oil, natural gas and natural gas liquids (“NGL”) reserves, which are used to compute the Trust’s amortization of investment in royalty interests and, as necessary, to evaluate potential impairment of its investment in royalty interests. Actual results could differ from those estimates.

Distributable Income Per Unit. Distributable income per unit amounts as calculated for the periods presented in the accompanying statements of distributable income may differ from declared distribution amounts per unit due to rounding and interest income. All Trust unitholders share on a pro rata basis in the Trust’s distributable income (See Note 1).

Cash and Cash Equivalents. Cash and cash equivalents consist of all highly-liquid instruments with original maturities of three months or less.

Investment in Royalty Interests. Significant dispositions or abandonments of the Underlying Properties are charged to investment in royalty interests and the trust corpus. Amortization of investment in royalty interests is calculated on a units-of-production basis, whereby the Trust’s cost basis is divided by the proved reserves attributable to the Royalty Interests to derive an amortization rate per reserve unit. Amortization is recorded when units are produced. Such amortization does not reduce distributable income, rather it is charged directly to trust corpus. Revisions to estimated future units-of-production are treated on a prospective basis beginning on the date significant revisions are known.

Impairment of Investment in Royalty Interests. On a quarterly basis, the Trust evaluates the carrying value of the Investment in Royalty Interests by comparing the undiscounted cash flows expected to be realized from the Royalty Interest to the carrying value. If the expected future undiscounted cash flows are less than the carrying value, the Trust recognizes an impairment loss for the difference between the carrying value and the estimated fair value of the Royalty Interest, which is determined using future cash flows of the net oil, natural gas and NGL reserves attributable to the Royalty Interests, discounted at a rate based upon the weighted average cost of capital of publicly traded royalty trusts. The weighted average cost of capital is based upon inputs that are readily available in the public market. The future cash flows of the net oil, natural gas and NGL reserves attributable to the Royalty Interests utilizes the oil and natural gas futures prices readily available in the public market adjusted for differentials and estimated quantities of oil, natural gas and NGL reserves that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. As there are numerous uncertainties inherent in estimating quantities of proved reserves, these quantities are a significant unobservable input resulting in the fair value measurement being considered a level 3 measurement within the fair value hierarchy. There were no impairments in the carrying value of the Investment in Royalty Interests during 2018 or 2017. Material write-downs in subsequent periods may occur if commodity prices decline. Any impairment would result in a non-cash charge to trust corpus and would not affect the Trust's distributable income. See “Risks and Uncertainties” in Note 5 below for further discussion.

Revenue and Expenses. Revenues received by the Trust are reduced by post-production expenses, production taxes and general and administrative expenses paid and are adjusted for amounts received or paid under its derivative contracts and cash reserves withheld by the Trustee in order to determine distributable income. The Royalty Interests are not burdened by field and lease operating expenses.

Concentration of Risk. The Trust maintains cash balances at one financial institution which are insured by the Federal Deposit Insurance Corporation up to $250,000. The Trust typically has balances in these accounts that substantially exceed the federally insured limit. The Trust does not anticipate any loss associated with balances exceeding the federally insured limit.

3. Income Taxes

The Trust is treated as a partnership for federal and applicable state income tax purposes. For U.S. federal income tax purposes, a partnership is not a taxable entity and incurs no U.S. federal income tax liability. With respect to state taxation, a partnership is typically treated in the same manner as it is for U.S. federal income tax purposes. However, the Trust's activities result in the Trust having nexus in Texas and, therefore, make it subject to Texas franchise tax. Texas franchise tax is treated as an income tax for financial statement purposes. The Trust is required to pay Texas franchise tax each year at a maximum effective rate (subject to changes in the statutory rate) of 0.525% of its gross income apportioned to Texas. The Trust records Texas franchise tax when paid. The Trust paid its 2017 Texas franchise tax of approximately $0.1 million during the year ended December 31, 2018. The Trust paid its 2016 Texas franchise tax of approximately $0.1 million during the year ended December 31, 2017. The Trust expects to pay its estimated 2018 Texas franchise tax liability of approximately $0.1 million during the year ending December 31, 2019. Further, the Trust's tax years 2014 to present remain open for examination with respect to Texas franchise tax.

4. Distributions to Unitholders

The Trust makes quarterly cash distributions of substantially all of its cash receipts, after deducting amounts for the Trust's administrative expenses, property tax and Texas franchise tax and cash reserves withheld by the Trustee, on or about the 60th day following the completion of each quarter. Distributions cover a three-month production period. A summary of the Trust's distributions to unitholders is as follows:

	Covered Production Period	Date Declared	Date Paid	Total Distribution Paid (in millions)		Distribution Per Common Unit	
Calendar Quarter 2018							
First Quarter	September 1, 2017 - November 30, 2017	January 25, 2018	February 23, 2018	$	5.9	$	0.113
Second Quarter	December 1, 2017 - February 28, 2018	April 26, 2018	May 25, 2018	$	6.6	$	0.125
Third Quarter	March 1, 2018 - May 31, 2018	July 26, 2018	August 24, 2018	$	6.8	$	0.129
Fourth Quarter	June 1, 2018 - August 31, 2018	October 25, 2018	November 23, 2018	$	6.0	$	0.115
Calendar Quarter 2017							
First Quarter	September 1, 2016 - November 30, 2016	January 26, 2017	February 24, 2017	$	6.3	$	0.120
Second Quarter	December 1, 2016 - February 28, 2017	April 27, 2017	May 26, 2017	$	6.8	$	0.130
		July 27, 2017		$	6.2	$	0.119

Third Quarter	March 1, 2017 - May 31, 2017		August 25, 2017				
Fourth Quarter	June 1, 2017 - August 31, 2017	October 26, 2017	November 24, 2017	$	5.0	$	0.095

On February 22, 2019, the Trust paid a cash distribution covering production for the period from September 1, 2018 to November 30, 2018. See Note 8 for further discussion.

5. Commitments and Contingencies

Loan Commitment. Pursuant to the trust agreement, if at any time the Trust's cash on hand (including available cash reserves) is not sufficient to pay the Trust's ordinary course administrative expenses as they become due, Avalon will, at the Trustee's request, loan funds to the Trust necessary to pay such expenses. Any funds loaned by Avalon pursuant to this commitment will be limited to the payment of current accounts payable or other obligations to trade creditors in connection with obtaining goods or services or the payment of other current liabilities arising in the ordinary course of the Trust's business, and may not be used to satisfy Trust indebtedness, or to make distributions. If Avalon loans funds pursuant to this commitment, unless Avalon agrees otherwise, no further distributions will be made to unitholders (except in respect of any previously determined quarterly cash distribution amount) until such loan is repaid. Any such loan will be on an unsecured basis, and the terms of such loan will be substantially the same as those which would be obtained in an arm's length transaction between Avalon and an unaffiliated third party. No such loan from Avalon was outstanding at December 31, 2018 or 2017.

Risks and Uncertainties. The Trust's revenue and distributions are substantially dependent upon the prevailing and future prices for oil and natural gas, each of which depends on numerous factors beyond the Trust's control such as overall oil and natural gas production and inventories in relevant markets, economic conditions, the global political environment, regulatory developments and competition from other energy sources. Oil and natural gas prices historically have been volatile, and may be subject to significant fluctuations in the future. Low levels of future production and continued low commodity prices would continue to reduce the Trust's revenues and distributable income available to unitholders.

The Trust is highly dependent on Avalon for multiple services, including the operation of the Trust wells, remittance of net proceeds from the sale of associated production to the Trust, administrative services such as accounting, tax preparation, bookkeeping and informational services performed on behalf of the Trust, and potentially for loans to pay Trust administrative expenses. Avalon is a newly formed company with no operating history. Its activities to date have been limited to organizational efforts, assembling a management team, raising capital, researching and developing its business plan, and completing the Sale Transaction. The ability to operate the properties depends on Avalon's future financial condition and economic performance, access to capital, and other factors, many of which are out of the control of Avalon's control.

6. Related Party Transactions

Trustee Administrative Fee. Under the terms of the trust agreement, the Trust pays an annual administrative fee to the Trustee, which prior to 2017 was $150,000. The annual administrative fee can be adjusted for inflation by no more than 3% in any year. The Trustee's administrative fees paid during the years ended December 31, 2018 and 2017 totaled approximately $155,000 and $152,000, respectively.

Registration Rights Agreement. The Trust is party to a registration rights agreement pursuant to which the Trust has agreed to register the offering of the Trust units now held by Avalon upon request by Avalon. The holders have the right to require the Trust to file no more than five registration statements in aggregate, one of which has been filed to date. The Trust does not bear any expenses associated with such transactions.

Administrative Services Agreement. The Trust has been a party to an administrative services agreement with SandRidge that obligates the Trust to pay SandRidge an annual administrative services fee in the amount of $300,000, which is payable in equal quarterly installments and remains fixed for the life of the Trust, for accounting, tax preparation, bookkeeping and informational services performed by SandRidge on behalf of the Trust. SandRidge is also entitled to receive reimbursement for its out-of-pocket fees, costs and expenses incurred in connection with the provision of any of the services under this agreement. In connection with the Sale Transaction, Avalon assumed the responsibility to provide such services to the Trust under the terms of the administrative services agreement beginning in the first quarter of 2019. Effective January 1, 2019, Avalon will begin receiving the annual fee of $300,000 and reimbursement of its out-of-pocket fees, costs and expenses incurred in connection with the provision of the administrative services to the Trust.

7. Major Customers

For the years ended December 31, 2018 and 2017, sales of production attributable to the Royalty Interests exceeding 10% of the Trust's total revenues were made to the following oil or natural gas purchasers:

	Sales (in thousands)		% of Revenue	
2018				
Enterprise Crude Oil LLC	$	22,685	76.0	%
ConocoPhillips Company	$	4,917	16.5	%
2017				
Enterprise Crude Oil LLC	$	21,947	76.2	%
ConocoPhillips Company	$	4,550	15.8	%

8. Subsequent Events

On January 24, 2019, the Trust declared a cash distribution of $0.095 per unit covering production for the three-month period from September 1, 2018 to November 30, 2018 for record unitholders as of February 8, 2019. The distribution was paid on February 22, 2019. Distributable income for September 1, 2018 to November 30, 2018 was calculated as follows (in thousands, except for unit and per unit amounts):

Revenues		
Royalty income	$	6,243
Total revenues	6,243	
Expenses		
Post-production expenses	12	
Production taxes	300	
Cash reserves withheld by Trustee(1)	773	
Total expenses	1,085	
Distributable income	$	5,158
Additional cash reserve(2)		190
Distributable income available to unitholders	$	4,968
Distributable income per unit (52,500,000 units issued and outstanding)	$	0.095

(1) Includes amounts withheld for payment of future Trust administrative expenses.
(2) Cash reserve increase for the payment of future known, anticipated or contingent expenses or liabilities.

9. Supplemental Information on Oil and Natural Gas Producing Activities (Unaudited)

The following supplemental information includes capitalized costs related to oil and natural gas producing activities; costs incurred in oil and natural gas property acquisition, exploration and development; and the results of operations for oil and natural gas producing activities. Supplemental information is also provided for oil, natural gas and NGL production and average sales prices; the estimated quantities of proved oil, natural gas and NGL reserves; the standardized measure of discounted future net cash flows associated with proved oil, natural gas and NGL reserves; and a summary of the changes in the standardized measure of discounted future net cash flows associated with proved oil, natural gas and NGL reserves. This supplemental information was prepared on an accrual basis, which is the basis upon which SandRidge and the Underlying Properties maintain their records and is different from the modified cash basis on which the Trust financial statements are prepared. A reconciliation of information presented on the modified cash basis to the accrual basis for the years ended December 31, 2018 and 2017 is as follows:

	Year Ended December 31, 2018			
		For the period		
	Modified Cash Basis(1)	September 1, 2017 to December 31, 2017	September 1, 2018 to December 31, 2018	Accrual Basis (2)
Production Data (Unaudited)				
Oil (MBbls)	485.0	(168.3)	146.1	462.8
NGL (MBbls)	72.3	(25.4)	21.2	68.1
Natural Gas (MMcf)	227.3	(82.3)	67.2	212.2
Combined equivalent volumes (MBoe)(3)	595.2	(207.4)	178.5	566.3
Royalty Income (in thousands)	$ 29,806	$ (9,472)	$ 7,887	$ 28,221
Expenses (in thousands):				
Post-production costs	46	(1)	(2)	45
Property taxes	1,559	(43)	43	1,559
Production taxes	1,423	(451)	375	1,347
	$ 26,778	$ (8,979)	$ 7,471	$ 25,270

F-8

	Year Ended December 31, 2017			
		For the period		
	Modified Cash Basis(4)	September 1, 2016 to December 31, 2016	September 1, 2017 to December 31, 2017	Accrual Basis (2)
Production Data (Unaudited)				
Oil (MBbls)	583.8	(206.2)	168.3	545.9
NGL (MBbls)	83.0	(27.7)	25.4	80.7
Natural Gas (MMcf)	280.6	(100.3)	82.3	262.6
Combined equivalent volumes (MBoe)(3)	713.6	(250.6)	207.4	670.3
Royalty Income (in thousands)	$ 28,777	$ (9,972)	$ 9,472	$ 28,277
Expenses (in thousands):				
Post-production costs	58	(3)	(1)	54
Property taxes	2,223	(802)	43	1464
Production taxes	1,377	(473)	451	1,355
	$ 25,119	$ (8,694)	$ 8,979	$ 25,404

---

(1) Production volumes attributable to the Royalty Interests and related revenues and expenses included in SandRidge’s 2018 net revenue distributions to the Trust. Represents production from September 1, 2017 to August 31, 2018.
(2) Production volumes attributable to the Royalty Interests and related revenues and expenses, presented on an accrual basis for the years ended December 31, 2018 and 2017, respectively.
(3) Barrel of oil equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, which approximates the relative energy content of oil as compared to natural gas.
(4) Production volumes attributable to the Royalty Interests and related revenues and expenses included in SandRidge’s 2017 net revenue distributions to the Trust. Represents production from September 1, 2016 to August 31, 2017.

Capitalized Costs Related to Oil and Natural Gas Producing Activities

The Trust’s capitalized costs consisted of the following (in thousands):

	December 31, 2018		2017	
Investment in royalty interests				
Proved(1)	$	549,831	$	549,831
Unproved	—		—	
Total investment in royalty interests	549,831		549,831	
Less accumulated amortization and impairment	(436,973)		(425,955)	
Net investment in royalty interests	$	112,858	$	123,876

(1) Royalty Interests conveyed to the Trust by SandRidge were in proved properties only.

Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development

The Trust is not responsible for any costs incurred related to the Underlying Properties. As such, the Trust did not incur any costs in the exploration or development of oil and natural gas properties during the years ended December 31, 2018 or 2017.

Results of Operations for Oil and Natural Gas Producing Activities (Unaudited)

The Trust's results of operations from oil and natural gas producing activities for each of the years ended 2018 and 2017 are shown in the following table (in thousands):

	December 31,	
	2018(1)	2017(1)
Revenues	$ 28,272	$ 28,299
Expenses(2)		
Post-production costs	45	54
Property taxes	1,559	1,464
Production taxes	1,347	1,355
Amortization and impairment expense(3)	11,018	13,502
Income before income taxes	14,303	11,924
Income taxes(4)	47	47
Results of operations for oil and natural gas producing activities (excluding general and administrative costs and derivative settlements of the Trust)	$ 14,256	$ 11,877

(1) Revenues and post-production costs attributable to volumes produced from January 1 to December 31 of the respective year, regardless of whether proceeds from the sale of production have been remitted to the Trust by SandRidge.
(2) The Trust does not bear any well operating costs.
(3) Amortization is recorded by the Trust as volumes are produced and does not reduce distributable income, but rather, is recorded directly to trust corpus.
(4) Reflect Trust's effective state income tax rate of 0.1655%. The Trust is not required to pay federal income tax.

Oil, Natural Gas and NGL Reserve Quantities (Unaudited)

Proved reserves are those quantities of oil, natural gas and NGL, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible, based on prices used to estimate reserves, from a given date forward from known reservoirs, and under existing economic conditions, operating methods, and government regulation before the time of which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. Proved developed reserves are proved reserves 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 with the cost of a new well. Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively large major expenditure is required for recompletion.

Netherland, Sewell & Associates, Inc. (“Netherland Sewell”), independent oil and natural gas consultants, prepared the estimates of proved reserves of oil, natural gas and NGL attributable to the Royalty Interests. Netherland Sewell are independent petroleum engineers, geologists, geophysicists and petrophysicists and do not own an interest in the Trust or its properties and are not employed on a contingent basis.

Based on its review of the estimates of proved reserves made by the independent petroleum engineers, SandRidge has advised the Trustee that the geoscience and engineering data examined provides reasonable assurance that the proved reserves are economically producible in future years from known reservoirs, and under existing economic conditions, operating methods and governmental regulations. Estimates of proved reserves are subject to change, either positively or negatively, as additional information is available and contractual and economic conditions change.

The table below represents the estimate of proved reserves attributable to the Trust’s net interest in oil and natural gas properties, all of which are located in the continental United States, based upon the evaluation by the Trustee and its independent petroleum engineers of pertinent geoscience and engineering data in accordance with the SEC’s regulations. Estimates of the Trust’s proved reserves have been prepared by independent reservoir engineers and geoscience professionals and are reviewed by members of SandRidge’s senior management with professional training in petroleum engineering to ensure that rigorous professional standards and the reserve definitions prescribed by the SEC are consistently applied.

The summary below presents changes in the Trust's estimated reserves during the years ended December 31, 2017 and 2018.

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)(1)
Proved developed and undeveloped reserves			
As of December 31, 2016	5,075.2	734.6	2,417.5
Revisions of previous estimates	470.6	105.0	389.5
Extensions and discoveries	—	—	—
Production(2)	(545.9)	(80.7)	(262.6)
As of December 31, 2017	4,999.9	758.9	2,544.4
Revisions of previous estimates	30.4	1.0	(168.4)
Extensions and discoveries	—	—	—
Production(2)	(462.8)	(68.1)	(212.2)
As of December 31, 2018	4,567.5	691.8	2,163.8
Proved developed reserves(3)			
As of December 31, 2017	4,999.9	758.9	2,544.4
As of December 31, 2018	4,567.5	691.8	2,163.8
Proved undeveloped reserves(3)			
As of December 31, 2017	—	—	—

As of December 31, 2018	—	—	—

(1) Natural gas reserves are computed at 14.65 pounds per square inch absolute and 60 degrees Fahrenheit.
(2) Volumes produced from January 1 to December 31 of the respective year, regardless of whether proceeds from the sale of such production have been remitted to the Trust by SandRidge.
(3) Estimated proved reserves were determined using a 12-month average price for oil, natural gas and NGL.

The Trust recognized net additions to reserves associated with proved properties of approximately, 3.3 MBoe and 640.5 MBoe as a result of pricing and well performance during 2018 and 2017, respectively.

Standardized Measure of Discounted Future Net Cash Flows (Unaudited)

The assumptions underlying the computation of the standardized measure of discounted cash flows are summarized as follows:

•the standardized measure includes estimates of proved oil, natural gas and NGL reserves and projected future production volumes based upon economic conditions;

•pricing is applied based upon 12-month average market prices at December 31, 2018 and 2017. The calculated weighted average per unit prices for the Trust's proved reserves and future net revenues were as follows;

	December 31, 2018	2017
Oil (per barrel)	$ 59.12	$ 47.70
NGL (per barrel)	$ 24.91	$ 20.07
Natural Gas (per Mcf)	$ 1.89	$ 2.13

•a discount factor of 10% per year is applied annually to the future net cash flows; and

•future income tax expenses are computed based upon the estimated effective state income tax rates of 0.1655%. The Trust is not required to pay federal income taxes.

F-11

The summary below presents the Trust’s future net cash flows relating to proved oil, natural gas and NGL reserves based on the standardized measure in ASC Topic 932 (in thousands).

	As of December 31, 2018	2017
Future cash inflows from production	$ 291,358	$ 259,136
Future production costs(1)	(22,896)	(21,150)
Future income taxes	(482)	(429)
Undiscounted future net cash flows	267,980	237,557
10% annual discount	(132,493)	(114,574)
Standardized measure of discounted future net cash flows	$ 135,487	$ 122,983

(1) Includes the Trust’s proportionate share of production taxes and post-production costs. The Trust does not bear any development or operational costs related to wells.

The following table represents the Trust’s estimate of changes in the standardized measure of discounted future net cash flows from proved reserves (in thousands):

Present value as of December 31, 2016	$ 109,600
Revenues less post-production and other costs	(25,403)
Net changes in prices, production and other costs	22,321
Revisions of previous quantity estimates	13,275
Accretion of discount	9,927
Net changes in income taxes	92

Timing differences and other(1)	(6,829)	
Net change for the year	13,383	
Present value as of December 31, 2017	$	122,983
Revenues less post-production and other costs	(25,269)	
Net changes in prices, production and other costs	27,269	
Revisions of previous quantity estimates	716	
Accretion of discount	11,217	
Net changes in income taxes	(22)	
Timing differences and other(1)	(1,407)	
Net change for the year	12,504	
Present value as of December 31, 2018	$	135,487

(1) Changes in timing differences and other are related to revisions in the estimated timing of production and, as applicable, development.

10. Quarterly Financial Results (Unaudited)

The Trust’s operating results for each calendar quarter of 2018 and 2017 are summarized below (in thousands, except per unit data).

	First Quarter (1)		Second Quarter (2)		Third Quarter (3)		Fourth Quarter (4)	
2018								
Royalty income	$	6,925	$	7,737	$	7,984	$	7,211
Distributable income available to	$	5,935	$	6,568	$	6,781	$	6,042

unitholders								
Distributable income per common unit	$	0.113	$	0.125	$	0.129	$	0.115

F-12

	First Quarter (5)	Second Quarter (6)	Third Quarter (7)	Fourth Quarter (8)
2017				
Royalty income	$ 7,238	$ 7,835	$ 7,208	$ 6,518
Distributable income available to unitholders	$ 6,326	$ 6,831	$ 6,208	$ 4,975
Distributable income per common unit	$ 0.120	$ 0.130	$ 0.118	$ 0.095

(1) Includes proceeds attributable to production from the Royalty Interests from September 1, 2017 to November 30, 2017.

(2) Includes proceeds attributable to production from the Royalty Interests from December 1, 2017 to February 28, 2018.

(3) Includes proceeds attributable to production from the Royalty Interests from March 1, 2018 to May 31, 2018.

(4) Includes proceeds attributable to production from the Royalty Interests from June 1, 2018 to August 31, 2018.

(5) Includes proceeds attributable to production from the Royalty Interests from September 1, 2016 to November 30, 2016.

(6) Includes proceeds attributable to production from the Royalty Interests from December 1, 2016 to February 28, 2017.

(7) Includes proceeds attributable to production from the Royalty Interests from March 1, 2017 to May 31, 2017.

(8) Includes proceeds attributable to production from the Royalty Interests from June 1, 2017 to August 31, 2017.