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

FORM 10-K

(Mark One)

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

For the Fiscal Year Ended December 31, 2013

or

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

For the transition period from to

Commission File Number 001-35532

PACIFIC COAST OIL TRUST
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**80-6216242** (I.R.S. Employer Identification No.)
The Bank of New York Mellon Trust Company, N.A., Trustee **Global Corporate Trust** **919 Congress Avenue, Suite 500** **Austin, Texas** (Address of principal executive offices)	**78701** (Zip Code)

Registrant's telephone number, including area code: **(800) 852-1422**

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

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

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

None
(Title of class)

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

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

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

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

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

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

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

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

The aggregate market value of the 18,500,000 Units of Beneficial Interest in Pacific Coast Oil Trust held by non-affiliates of the registrant at the closing price on June 28, 2013 of $18.03 was approximately $333,555,000.

As of March 14, 2014, 38,583,158 Units of Beneficial Interest of the Trust were outstanding.

Documents Incorporated By Reference: **None**

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References to the “Trust” in this document refer to Pacific Coast Oil Trust, while references to “PCEC” in this document refer to Pacific Coast Energy Company LP, a privately held Delaware partnership.

FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical fact included in this Form 10-K, including without limitation the statements under “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Risk Factors” regarding the financial position, business strategy, production and reserve growth, and other plans and objectives for the future operations of PCEC and any statements regarding future matters regarding the Trust are forward-looking statements. Such statements may be influenced by factors that could cause actual outcomes and results to differ materially from those projected. No assurance can be given that such expectations will prove to have been correct. When used in this document, the words “believes,” “expects,” “anticipates,” “intends” or similar expressions are intended to identify such forward-looking statements. The following important factors, in addition to those discussed elsewhere in this Form 10-K, could affect the future results of the energy industry in general, and PCEC and the Trust in particular, and could cause actual results to differ materially from those expressed in such forward-looking statements:

- risks associated with the drilling and operation of oil and natural gas wells;
- the amount of future direct operating expenses and development expenses;
- the effect of existing and future laws and regulatory actions, including the failure to obtain necessary discretionary permits;
- the effect of changes in commodity prices or alternative fuel prices;
- the impact of any commodity derivative contracts;
- conditions in the capital markets;
- competition from others in the energy industry;
- uncertainty of estimates of oil and natural gas reserves and production; and
- cost inflation.

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

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

GLOSSARY OF CERTAIN OIL AND NATURAL GAS TERMS

In this report the following terms have the meanings specified below.

API —The specific gravity or density of oil expressed in terms of a scale devised by the American Petroleum Institute.

Bbl —One stock tank barrel of 42 U.S. gallons liquid volume, of oil or other liquid hydrocarbons.

Bbl/d —Bbl per day.

Boe —One stock tank barrel of oil equivalent, computed on an approximate energy equivalent basis that one Bbl of oil equals six Mcf of natural gas. This ratio does not reflect a price or revenue equivalency. Given commodity price disparities, the price for a barrel of oil equivalent for natural gas is significantly less than the price for a barrel of oil.

Boe/d —Boe per day.

Btu —A British Thermal Unit, which is the quantity of heat required to raise the temperature of a one-pound mass of water by one degree Fahrenheit.

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

Deterministic method —The method of estimating revenues using a single value for each parameter (from the geoscience engineering economic data) in reserves calculations.

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

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

Dry hole or well —A well found to be incapable of producing either oil and gas in sufficient quantities to justify completion as an oil or gas well.

Economically producible —A resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

Exploratory well —A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is not a development well.

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

FASB —Financial Accounting Standards Board.

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

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

ICE —Intercontinental Exchange.

MBbl —One thousand barrels of crude oil or condensate.

MBoe —One thousand barrels of oil equivalent.

Mcf —One thousand cubic feet of natural gas.

MMBbl —One million barrels of crude oil or other liquid hydrocarbons.

MMBoe —One million barrels of oil equivalent.

MMBtu —One million British Thermal Units.

MMcf —One million cubic feet of natural gas.

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

NGLs — The combination of ethane, propane, butane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

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

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

NYMEX —New York Mercantile Exchange.

Oil —Crude oil and condensate.

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

Overriding royalty interest —A fractional, undivided interest or right of participation in the oil or gas, or in the proceeds from the sale of oil and gas, that is limited in duration to the term of an existing lease and that is not subject to the expenses of development, operation or maintenance.

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

Proved developed reserves —Proved reserves 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. This definition of proved developed reserves has been abbreviated from the applicable definition contained in Rule 4-10(a)(6) of Regulation S-X.

Proved reserves —The estimated quantities of oil, NGLs, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be economically producible in future years from known reservoirs under existing economic and operating conditions and government regulations. 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. This definition of proved reserves has been abbreviated from the applicable definitions contained in Rule 4-10(a)(22) of Regulation S-X.

Proved undeveloped reserves or PUDs —Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. This definition of proved undeveloped reserves has been abbreviated from the applicable definitions contained in Rule 4-10(a)(31) of Regulation S-X.

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

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

Standardized measure — The present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (using prices and costs in effect as of the date of estimation), less future development, production and income tax expenses, and discounted at 10% per annum to reflect the timing of future net revenue. Standardized measure does not give effect to derivative transactions.

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 natural gas and oil regardless of whether such acreage contains proved reserves.

US GAAP — Generally accepted accounting principles in the United States.

West Texas Intermediate ("WTI") —Light, sweet crude oil with high API gravity and low sulfur content used as the benchmark for U.S. crude oil refining and trading. WTI is deliverable at Cushing, Oklahoma to fill NYMEX futures contracts for light, sweet crude oil.

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

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

PART I

Item 1. Business.

Pacific Coast Oil Trust (the “Trust”) is a Delaware statutory trust formed in January 2012 under the Delaware Statutory Trust Act pursuant to a Trust Agreement among Pacific Coast Energy Company LP (“PCEC”), as trustor, The Bank of New York Mellon Trust Company, N.A., as Trustee (the “Trustee”), and Wilmington Trust, National Association, as Delaware Trustee (the “Delaware Trustee”). The Trust Agreement was amended and restated by PCEC, the Trustee and the Delaware Trustee on May 8, 2012. References in this report to the “Trust Agreement” are to the amended and restated trust agreement.

The Trust was created to acquire and hold net profits and royalty interests in certain oil and natural gas properties located in California for the benefit of the Trust unitholders. On May 8, 2012, the Trust and PCEC entered into a Conveyance of NPI and Overriding Royalty Interest (the “Conveyance”), pursuant to which PCEC conveyed to the Trust the Net Profits Interest and the Royalty Interest, which are collectively referred to herein as the “Conveyed Interests”. The Conveyed Interests represent undivided interests in underlying properties consisting of PCEC’s interests in its oil and natural gas properties located onshore in California (the “Underlying Properties”). The Conveyed Interests were conveyed by PCEC to the Trust concurrent with the initial public offering (“IPO”) of the Trust’s common units in May 2012.

Concurrent with the Conveyance, PCEC sold 18,500,000 Trust Units to the public in the IPO. The proceeds (net of underwriting discounts of approximately $23.0 million) received by PCEC (before expenses) from the sale of 18,500,000 Trust Units were approximately $346.9 million. The Trust received no proceeds from the sale of the Trust Units. The IPO is described in the final Prospectus filed with the Securities and Exchange Commission pursuant to Rule 424(b)(1) on May 4, 2012 (the “Prospectus”). Upon completion of the offering, there were 38,583,158 Trust Units issued and outstanding, of which PCEC owned 20,083,158 Trust Units, or 52% of the issued and outstanding Trust Units.

On September 19, 2013, the Trust, PCEC and other persons or entities parties signatory thereto (the “Other Selling Unitholders” entered into an Underwriting Agreement (the “Underwriting Agreement”), with the underwriters named therein (the “Underwriters”), with respect to the offer and sale (the “Offering”) by PCEC and the Other Selling Unitholders. On September 23, 2013, PCEC distributed 11,216,661 Trust Units to the Other Selling Unitholders. Immediately following the distribution on September 23, 2013, the Other Selling Unitholders sold 8,500,000 Trust Units, and PCEC sold an additional 5,000,000 Trust Units, for a total sale of 13,500,000 Trust Units. PCEC retained 3,866,497 Trust Units, or 10% of the issued and outstanding Trust Units. The Trust received no proceeds from the sale of any of these Trust Units.

The Conveyed Interests are passive in nature and neither the Trust nor the Trustee has any control over, or responsibility for, costs relating to the operation of the Underlying Properties. The Underlying Properties consist of (i) the proved developed reserves as of December 31, 2011 on the Underlying Properties, which are referred to as the “Developed Properties,” and (ii) all other development potential on the Underlying Properties, which are referred to as the “Remaining Properties.” Production from the Developed Properties attributable to the Trust is produced from wells that, because they have already been drilled, require limited additional capital expenditures. Production from the Remaining Properties that is attributable to the Trust requires capital expenditures for the drilling of wells and installation of infrastructure. PCEC supplies the required capital on behalf of the Trust during this period; however, because the costs initially incurred exceed gross proceeds, the Remaining Properties currently have negative net profits during this drilling and development period. During this period of negative net profits, instead of being paid net profits, the Trust is paid a 7.5% overriding royalty on the portion of the Remaining Properties located on PCEC’s Orcutt properties (the “Royalty Interest Proceeds”). Once revenues from the Remaining Properties have paid back PCEC for the cumulative costs it has advanced on behalf of the Trust (referred to as the “25% Net Profits Interest Accrued Deficit Balance” and includes the payments made to the Trust pursuant to the 7.5% overriding royalty), then the NPI on the Remaining Properties will be paid out (“NPI Payout”) in place of the Royalty Interest Proceeds. These interests entitle the Trust to receive the following:

Developed Properties

- 80% of the net profits from the sale of oil and natural gas production from the Developed Properties.

Remaining Properties

- 7.5% of the proceeds (free of any production or development costs but bearing the proportionate share of production and property taxes and post-production costs) attributable to the sale of all oil and natural gas production from the Remaining Properties located on PCEC’s Orcutt properties, or

- 25% of the net profits from the sale of oil and natural gas production from all of the Remaining Properties.

The Trust has no employees. The business and affairs of the Trust are administered by the Trustee. The Trust's purpose is to hold the Conveyed Interests, to distribute to the Trust unitholders cash that the Trust receives in respect of the Conveyed Interests, subject to the effects of the commodity derivative contracts described in "—Commodity Derivative Contracts", and to perform certain administrative functions in respect of the Conveyed Interests and the Trust Units. The Trust does not conduct any operations or activities. The Trustee has no authority over or responsibility for, and no involvement with, any aspect of the oil and gas operations or other activities on the Underlying Properties. The Delaware Trustee has only minimal rights and duties as are necessary to satisfy the requirements of the Delaware Statutory Trust Act. The Trust derives all or substantially all of its income and cash flow from the Conveyed Interests, subject to the effects of the commodity derivative contracts. The Trust is treated as a grantor trust for U.S. federal income tax purposes.

The Trustee can authorize the Trust to borrow money to pay Trust administrative or incidental expenses that exceed cash held by the Trust. The Trustee may authorize the Trust to borrow from the Trustee or an affiliate as a lender provided the terms of the loan are fair to the Trust unitholders and similar to the terms it would grant to a similarly situated commercial customer with whom it did not have a fiduciary relationship, although neither the Trustee nor any of its affiliates has any intention of lending or obligation to lend funds to the Trust. The Trustee may also deposit funds awaiting distribution in an account with itself, if the interest paid to the Trust at least equals amounts paid by the Trustee on similar deposits, and make other short-term investments with the funds distributed to the Trust.

In connection with the formation of the Trust, the Trust entered into several agreements with PCEC that impose obligations upon PCEC that are enforceable by the Trustee on behalf of the Trust, including the Conveyance, an operating and services agreement and a registration rights agreement. The operating and services agreement provides that PCEC performs specified operating and informational services on behalf of the Trust in a good and workmanlike manner in accordance with the sound and prudent practices of providers of similar services. The Trustee has the power and authority under the Trust Agreement to enforce these agreements on behalf of the Trust. The Trustee may from time to time supplement or amend the Conveyance, the operating and services agreement and the registration rights agreement without the approval of Trust unitholders in order to cure any ambiguity, to correct or supplement any defective or inconsistent provisions, to grant any benefit to all of the Trust unitholders, to comply with changes in applicable law or to change the name of the Trust. Such supplement or amendment, however, may not materially adversely affect the interests of the Trust unitholders. Additionally, the Trustee may, from time to time, supplement or amend these agreements without the approval of the Trust unitholders as long as such supplement or amendment would not materially increase the costs or expenses of the Trust or adversely affect the economic interest of the Trust unitholders; however, the Trustee may not modify or amend the Conveyance if the modification or amendment would change the character of the Conveyed Interests in such a way that the Conveyed Interests become working interests or that the Trust would fail to continue to qualify as a grantor trust for U.S. federal income tax purposes. The Trustee is entitled to rely upon a written opinion of counsel or certification of PCEC as conclusive evidence that any such amendment or supplement is authorized.

Other than Trust administrative expenses, including any reserves established by the Trustee for future liabilities, the Trust's only use of cash is for distributions to Trust unitholders. Available funds are the excess cash, if any, received by the Trust from the Conveyed Interests and other sources (such as interest earned on any amounts reserved by the Trustee) in that month, over the Trust's expenses paid for that month. Available funds are reduced by any cash the Trustee determines to hold as a reserve against future expenses.

The Trustee may create a cash reserve to pay for future liabilities of the Trust. If the Trustee determines that the cash on hand and the cash to be received are, or will be, insufficient to cover the Trust's liabilities, the Trustee may cause the Trust to borrow funds to pay liabilities of the Trust. The Trustee may also cause the Trust to mortgage its assets to secure payment of the indebtedness. If the Trustee causes the Trust to borrow funds, the Trust unitholders will not receive distributions until the borrowed funds are repaid. As of December 31, 2013 the Trust had reserves of $39,005 for future Trust expenses. The Trust calculates net profits and royalties from the Underlying Properties separately for each of the Developed Properties and the Remaining Properties. Any excess costs for either the Developed Properties or the Remaining Properties will not reduce net profits calculated for the other. Accordingly, the cash on hand for either the Developed Properties or the Remaining Properties will not be applied to cover the costs of the other.

Each month, the Trustee pays Trust obligations and expenses and distributes to the Trust unitholders the remaining proceeds received from the Conveyed Interests. The cash held by the Trustee as a reserve against future liabilities or for distribution at the next distribution date may be invested in a limited number of permitted investments. Alternatively, cash held for distribution at the next distribution date may be held in a noninterest bearing account.

PCEC provided the Trust with a $1.0 million letter of credit to be used by the Trust in the event that its cash on hand (including available cash reserves) is not sufficient to pay ordinary course administrative expenses as they become due. Further, if the Trust requires more than the $1.0 million under the letter of credit to pay administrative expenses, PCEC has agreed to loan funds to the Trust necessary to pay such expenses. Any funds provided under the letter of credit or loaned by PCEC may only be used for the payment of current accounts or other obligations to trade creditors in connection with obtaining goods or services or for the payment of other accrued current liabilities arising in the ordinary course of the Trust's business, and may not be used to satisfy Trust indebtedness. If the Trust draws on the letter of credit or PCEC loans funds to the Trust, no further distributions will be made to Trust unitholders (except in respect of any previously determined monthly cash distribution amount) until such amounts drawn or borrowed, including interest thereon, are repaid in fall. Any loan made by PCEC 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 PCEC and an unaffiliated third party.

The Trust is not subject to any pre-set termination provisions based on a maximum volume of oil or natural gas to be produced or the passage of time. The Trust will dissolve upon the earliest to occur of the following: (1) the Trust, upon approval of the holders of at least 75% of the outstanding Trust Units, sells the Conveyed Interests, (2) the annual cash received by the Trust attributable to the Conveyed Interests, in the aggregate, is less than $2.0 million for each of any two consecutive years, (3) the holders of at least 75% of the outstanding Trust Units vote in favor of dissolution or (4) the Trust is judicially dissolved.

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

Marketing and Post-Production Services

Pursuant to the terms of the Conveyance creating the Conveyed Interests, PCEC has the responsibility to market, or cause to be marketed, the oil and natural gas production attributable to the Conveyed Interests. The terms of the Conveyance creating the Conveyed Interests restrict PCEC from charging any fee for marketing production attributable to the NPI other than fees for marketing paid to non-affiliates. Accordingly, a marketing fee will not be deducted (other than fees paid to non-affiliates) in the calculation of the NPI; however, the terms of the Conveyance provide that costs and expenses PCEC allocates to marketing production from the Underlying Properties are deducted from the calculation of gross profits. The Royalty Interest Proceeds are free of any production or development costs but are subject to a proportionate share of production and property taxes and post-production costs. The net profits and royalties to the Trust from the sales of oil and natural gas production from the Underlying Properties attributable to the Conveyed Interests are determined based on the same price that PCEC receives for sales of oil and natural gas production attributable to PCEC's interest in the Underlying Properties. However, in the event that the oil or natural gas is processed, the net profits and royalties receive the same processing upgrade or downgrade as PCEC.

During the year ended December 31, 2013, PCEC sold the oil produced from the Underlying Properties to third-party oil purchasers. Oil production from the Underlying Properties is typically transported by pipeline from the field to a gathering facility or refinery. PCEC sells the majority of the oil production from the Underlying Properties under contracts using market sensitive pricing. The price received by PCEC for the oil production from the Underlying Properties is usually based on a regional price applied to equal daily quantities in the month of delivery that is then reduced for differentials based upon delivery location and oil quality. Substantially all of PCEC's oil sales are indexed to the Buena Vista and Midway Sunset postings in California. Light crude production from the Orcutt Conventional, West Pico, Sawtelle, and East Coyote properties is indexed to the Buena Vista posting. Heavy crude production from the Orcutt diatomite formation is indexed to the Midway Sunset Formation.

In 2013, Phillips 66 accounted for 94% of PCEC's net sales. Phillips 66's purchase of production from the Orcutt properties is pursuant to a sales contract between Phillips 66 and PCEC that expires on December 31, 2015 and includes an option to renegotiate prices annually. Its purchase of production from West Pico properties is pursuant to a month-to-month sales contract.

All natural gas produced by PCEC in Orcutt is consumed in its diatomite production; all other natural gas produced is marketed and sold to third-party purchasers. In all cases, the contract price is based on a percentage of a published regional index price, after adjustments for Btu content, transportation and related charges.

Competition and Markets

The oil and natural gas industry is highly competitive. PCEC competes with major oil and natural gas companies and independent oil and natural gas companies for oil and natural gas, equipment, personnel and markets for the sale of oil and natural gas. Many of these competitors are financially stronger than PCEC, but even financially troubled competitors can affect the market because of their need to sell oil and natural gas at any price to attempt to maintain cash flow. The Trust is subject to the same competitive conditions as PCEC and other companies in the oil and natural gas industry.

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

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

Description of Trust Units

Each Trust unit is a unit of beneficial interest in the Trust assets and is entitled to receive cash distributions from the Trust on a pro rata basis. Each Trust unitholder has the same rights regarding each of his Trust Units as every other Trust unitholder has regarding his units. The Trust Units are in book-entry form only and are not represented by certificates. The Trust had 38,583,158 Trust Units outstanding as of December 31, 2013.

Distributions and Income Computations

Each month, the Trustee determines the amount of funds available for distribution to the Trust unitholders. Available funds are the excess cash, if any, received by the Trust from the Conveyed Interests and other sources (such as interest earned on any amounts reserved by the Trustee) that month, over the Trust's liabilities for that month. Available funds are reduced by any cash the Trustee determines to hold as a reserve against future liabilities. The holders of Trust Units as of the applicable record date (generally within five business days after the last business day of each calendar month) are entitled to monthly distributions payable on or before the 10th business day after the record date.

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

Transfer of Trust Units

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

Periodic Reports

The Trustee files all required Trust federal and state income tax and information returns. The Trustee prepares and mails to Trust unitholders annual reports that Trust unitholders need to correctly report their share of the income and deductions of the Trust. The Trustee also causes to be prepared and filed reports which are required to be filed under the Exchange Act and by the rules of The New York Stock Exchange, and also causes the Trust to comply with applicable provisions of the Sarbanes-Oxley Act, including but not limited to, establishing, evaluating and maintaining a system of internal control over financial reporting.

Pursuant to the operating and services agreement, PCEC has agreed to provide to the Trust such services as are necessary for the Trust and the Trustee to comply with the Trust Agreement and Article IV of the Conveyance, and such other operating and administrative services of similar character and scope to the foregoing that the Trustee may reasonably request PCEC to provide, including such accounting, bookkeeping and informational services and other services as may be necessary for the preparation of reports the Trust is or may be required to prepare and/or file in accordance with applicable tax and securities laws, exchange listing rules and other requirements, including reserve reports and tax returns (collectively, the "Administrative Services").

Liability of Trust Unitholders

Under the Delaware Statutory Trust Act and the Trust agreement, 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. No assurance can be given, however, that the courts in jurisdictions outside of Delaware will give effect to such limitation.

Voting Rights of Trust Unitholders

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

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

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

In addition, certain amendments to the Trust agreement may be made by the Trustee without approval of the Trust unitholders.

Computation of NPI and Overriding Royalty Interest

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

NPI

The amounts paid to the Trust for each Net Profits Interest are based on, among other things, the definitions of "gross profits" and "net profits" contained in the Conveyance and described below. Under the Conveyance, net profits are computed monthly. Each calendar month, 80% of the net profits from the sale of oil and natural gas production from the Developed Properties will be paid to the Trust generally on or before the eighth business day after the last business day of the following month. For any monthly period during which costs for the Remaining Properties exceed gross proceeds, the Trust is entitled to receive the Royalty Interest Proceeds and the Trust continues to receive such proceeds until the first day of the month following an NPI Payout. In calendar months following an NPI Payout, 25% of the net profits from the sale of oil and natural gas production from all of the Remaining Properties will be paid to the Trust on or before the end of the following month. Due to significant planned capital expenditures to be made by PCEC on the Remaining Properties for the benefit of the Trust, PCEC expects the Trust to receive payments associated with the Remaining Properties in the form of Royalty Interest Proceeds until the NPI Payout occurs in approximately 2021.

"Gross profits" means the aggregate amount received by PCEC that is attributable to sales of oil and natural gas production from the Underlying Properties from and after April 1, 2012 (after deducting the appropriate share of all royalties and any overriding royalties, production payments and other similar charges and other than certain excluded proceeds (including, with respect to the Remaining Properties, the Royalty Interest, to the extent paid), as described in the Conveyance), including all proceeds and consideration received (i) for advance payments, (ii) under take-or-pay and similar provisions of production sales contracts (when credited against the price for delivery of production) and (iii) under balancing arrangements. Gross profits do not include consideration for the transfer or sale of any Underlying Property by PCEC or any subsequent owner to any new owner, unless the Net Profits Interest in such Underlying Property is released (as is permitted under certain circumstances). Gross profits also do not include any amount for oil or natural gas lost in production or marketing or used by the owner of the Underlying Properties in drilling, production and plant operations.

"Net profits" means gross profits less the following costs, expenses and, where applicable, losses, liabilities and damages all as actually incurred by PCEC from and after April 1, 2012 and attributable to production from the Underlying Properties from and after April 1, 2012 (as such items are reduced by any offset amounts, as described in the Conveyance):

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

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

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

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

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

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

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

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

- all costs and expenses for recording the Conveyance and, at the applicable times, terminations and/or releases thereof;
- all administrative hedge costs (in respect of commodity derivative contracts existing prior to the date of the conveyance, as further described in the Conveyance);
- all hedge settlement costs (in respect of commodity derivative contracts existing prior to the date of the conveyance, as further described in the Conveyance);
- amounts previously included in gross profits but subsequently paid as a refund, interest or penalty; and
- at the option of PCEC (or any subsequent owner of the Underlying Properties), amounts reserved for approved development expenditure projects, including well drilling, recompletion and workover costs, which amounts will at no time exceed $2.0 million in the aggregate, and will be subject to the limitations described below (provided that such costs shall not be debited from gross profits when actually incurred).

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

The Trust is not liable to the owners of the Underlying Properties, PCEC, or any other operator for any operating, capital or other costs or liabilities attributable to the Underlying Properties. In the event that the net profits relating to the Developed Properties for any computation period is a negative amount, the Trust will receive no payment for the Developed Properties for that period, and any such negative amount will be deducted from gross profits for the Developed Properties in the following computation period for purposes of determining the net profits relating to the Developed Properties for that following computation period. In the event that the net profits relating to the Remaining Properties for any computation period is a negative amount, the Trust is entitled to receive the Royalty Interest Proceeds.

Gross profits and net profits are calculated on a cash basis, except that certain costs, primarily ad valorem taxes and expenditures of a material amount, may be determined on an accrual basis.

Overriding Royalty Interest

For any monthly period during which costs for the Remaining Properties exceed gross proceeds, the Trust is entitled to receive an amount equal to 7.5% of the proceeds attributable to the sale of all production from the Remaining Properties located on PCEC’s Orcutt properties, including but not limited to PCEC’s interest in such production (free of any production or development costs but bearing its proportionate share of production and property taxes and post-production costs) (the “Royalty Interest”). Due to significant capital expenditures to be made by PCEC on the Remaining Properties for the benefit of the Trust, PCEC expects the Trust to receive payments associated with the Remaining Properties in the form of Royalty Interest Proceeds until the NPI Payout occurs in approximately 2021.

Proceeds from the sale of oil, natural gas liquids and natural gas production from the Remaining Properties located on PCEC’s Orcutt properties in any calendar month means the amount calculated based on actual sales volumes from such properties, in each case after deducting the Trust’s proportionate share of:

- any taxes levied on the severance or production of the oil, natural gas liquids and natural gas produced from such properties and any property taxes attributable to the oil, natural gas liquids and natural gas produced from the such properties; and
- post-production costs, which generally consists of costs incurred to gather, store, compress, transport, process, treat, dehydrate and market the oil, natural gas liquids and natural gas produced, as applicable (excluding costs for marketing services provided by PCEC).

Proceeds payable to the Trust from the sale of oil, natural gas liquids and natural gas production attributable to the Remaining Properties located on PCEC's Orcutt properties in any calendar month are not subject to any deductions for any expenses attributable to exploration, drilling, development, operating, maintenance or any other costs incident to the production of oil, natural gas liquids and natural gas attributable to such properties, including any costs to drill, complete or plug and abandon a well. Additionally, costs associated with any completion activities will be borne by PCEC or any third-party operator of the well.

Commodity Derivative Contracts

The revenues derived from the Underlying Properties depend substantially on prevailing oil prices and, to a lesser extent, natural gas prices. As a result, commodity prices also affect the amount of cash flow available for distribution to the Trust unitholders. Lower prices may also reduce the amount of oil and natural gas that PCEC or the third-party operators can economically produce. PCEC has entered into commodity derivative contracts to reduce the exposure of the revenues from oil production from the Underlying Properties to fluctuations in oil prices and to achieve more predictable cash flow. However, these contracts limit the amount of cash available for distribution if prices increase above the fixed hedge price. These contracts expire March 31, 2014, as described below. None of the Trust's exposure to natural gas prices is hedged.

PCEC entered into commodity derivative contracts with Wells Fargo Bank, National Association in order to mitigate the effects of falling commodity prices through March 31, 2014. The Trust is entitled to the effect of 2,000 barrels of daily swap volumes of ICE Brent crude oil at $115.00 per barrel during the twenty-four months ending March 31, 2014, proportional to the Trust's interest in the Developed Properties. After March 31, 2014, none of the production attributable to the Underlying Properties will be hedged. As a result, the amount of the cash distributions will be subject to the possibility of greater fluctuations after March 2014 due to changes in oil prices.

The Trust did not bear any commodity derivative settlement costs paid by PCEC, nor was it entitled to any commodity derivative payments received by PCEC, for periods prior to April 2012.

The amounts received by PCEC from the commodity derivative contract counterparty upon settlement of the commodity derivative contracts reduce the operating expenses related to the Underlying Properties in calculating net profits. In addition, the aggregate amounts paid by PCEC upon settlement of the commodity derivative contracts related to the Underlying Properties reduce the amount of net profits paid to the Trust.

Additional Provisions

If a controversy arises as to the sales price of any production, then for purposes of determining gross profit or the amount of Royalty Interest Proceeds:

- any proceeds that are withheld for any reason (other than at the request of PCEC) are not considered received until such time that the proceeds are actually collected;
- amounts received and promptly deposited with a nonaffiliated escrow agent will not be considered to have been received until disbursed to it by the escrow agent; and
- amounts received and not deposited with an escrow agent will be considered to have been received.

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

The Conveyance generally permits PCEC to transfer without the consent or approval of the Trust unitholders all or any part of its interest in the Underlying Properties, subject to the Conveyed Interests. The Trust unitholders are not entitled to any proceeds of a sale or transfer of PCEC's interest. Except in certain cases where the Conveyed Interests are released, following a sale or transfer, the Underlying Properties will continue to be subject to the Conveyed Interests, and the gross profits and if applicable, the royalties, attributable to the transferred property will be calculated for such transferred property on a stand-alone basis (as part of the computation of net profits and royalties described in this report), paid and distributed by the transferee to the Trust. PCEC will have no further obligations, requirements or responsibilities with respect to any such transferred interests, provided that PCEC delivers to the Trustee an agreement of the transferee of such transferred interests, reasonably satisfactory to the Trustee, in which such transferee assumes the responsibility to perform the Administrative

Services that PCEC is required to provide to the Trust pursuant to the operating and services agreement relating to the interests being transferred.

In addition, PCEC may, without the consent of the Trust unitholders, require the Trust to release the Conveyed Interests associated with any lease that accounts for less than or equal to 0.25% of the total production from the Underlying Properties in the prior twelve months, provided that the Conveyed Interests covered by such releases cannot exceed, during any twelve month period, an aggregate fair market value to the Trust of $500,000. These releases will be made only in connection with a sale by PCEC to a non-affiliate of the relevant Underlying Properties, are conditioned upon an amount equal to the fair market value (net of sales costs) to the Trust of such Conveyed Interests and will be treated as an offset amount against costs and expenses. PCEC has not identified for sale any of the Underlying Properties.

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

PCEC will have the right to release, surrender or abandon its interest in any Underlying Property if PCEC determines in good faith and in accordance with the reasonably prudent operator standard that such Underlying Property that will no longer produce (or be capable of producing) hydrocarbons in paying quantities (determined without regard to the Conveyed Interests). Where PCEC does not operate the Underlying Properties, PCEC is required to use commercially reasonable efforts to exercise its contractual rights to cause the operators of such Underlying Properties to act as a reasonably prudent operator. Upon such release, surrender or abandonment, the portion of the Conveyed Interests relating to the affected property will also be released, surrendered or abandoned, as applicable. PCEC will also have the right to abandon an interest in the Underlying Properties if (a) such abandonment is necessary for health, safety or environmental reasons or (b) the hydrocarbons that would have been produced from the abandoned portion of the Underlying Properties would reasonably be expected to be produced from wells located on the remaining portion of the Underlying Properties.

PCEC must maintain books and records sufficient to determine the amounts payable for the Conveyed Interests to the Trust. Monthly and annually, PCEC must deliver to the Trustee a statement of the computation of the net profits for each computation period. The Trustee has the right to inspect and review the books and records maintained by PCEC during normal business hours and upon reasonable notice. Each Trust unitholder and his representatives may examine, for any proper purpose, during reasonable business hours, the records of the Trust and the Trustee relating to the Trust, subject to such restrictions as are set forth in the Trust agreement.

Federal Income Tax Matters

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

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

Classification and Taxation of the Trust

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

The Trust will file annual information returns, reporting to the Trust unitholders all items of income, gain, loss, deduction and credit. The Trust will allocate these items of income, gain, loss, deduction and credit to Trust unitholders based on record ownership on the monthly record dates. It is possible that the IRS or another taxing authority could disagree with this allocation method and could assert that income and deductions of the Trust should be determined and allocated on a daily or prorated basis, which could require adjustments to the tax returns of the unitholders affected by this issue and result in an increase in the administrative expense of the Trust in subsequent periods.

Classification of the NPI and the Royalty Interest

For U.S. federal income tax purposes, the NPI attributable to the Developed Properties (the "Developed NPI"), Remaining Properties (the "Remaining NPI") and the Royalty Interest will have the tax characteristics of a mineral royalty interest to the extent, at the time of its creation, such Developed NPI, Remaining NPI or Royalty Interest is reasonably expected to have an economic life that corresponds substantially to the economic life of the mineral property or properties burdened thereby. Payments out of production that are received in respect of a mineral interest that constitutes a royalty interest for U.S. federal income tax purposes are taxable under current law as ordinary income subject to an allowance for cost or percentage depletion in respect of such income.

Based on the reserve report and representations made by PCEC regarding the expected economic life of the Underlying Properties and the expected duration of the Conveyed Interests, tax counsel to the Trust advised the Trust at the time of formation that the Developed NPI will and the Remaining NPI and the Royalty Interest should be treated as continuing, nonoperating economic interests in the nature of royalties payable out of production from the mineral interests they burden.

Consistent with the foregoing, PCEC and the Trust intend to treat the Conveyed Interests as mineral royalty interests for U.S. federal income tax purposes. The remainder of this discussion assumes that the Conveyed Interests are treated as mineral royalty interests. No assurance can be given that the IRS will not assert that any such interest should be treated differently. Any such different treatment could affect the amount, timing and character of income, gain or loss in respect of an investment in Trust Units.

Reporting Requirements for Widely-Held Fixed Investment Trusts

The Trustee assumes that some Trust Units are held by middlemen, as such term is broadly defined in the Treasury regulations (and includes custodians, nominees, certain joint owners and brokers holding an interest for a custodian street name, collectively referred to herein as "middlemen"). Therefore, the Trustee considers the Trust to be a non-mortgage widely held fixed investment trust ("WHFIT") for U.S. federal income tax purposes. The Bank of New York Mellon Trust Company, N.A., 919 Congress Avenue, Austin, Texas 78701, telephone number 1-800-852-1422, is the representative of the Trust that will provide the tax information in accordance with applicable Treasury regulations governing the information reporting requirements of the Trust as a WHFIT. Notwithstanding the foregoing, the middlemen holding Trust Units on behalf of unitholders, and not the Trustee of the Trust, are solely responsible for complying with the information reporting requirements under the Treasury regulations with respect to such Trust Units, including the issuance of IRS Forms 1099 and certain written tax statements. Unitholders whose Trust Units are held by middlemen should consult with such middlemen regarding the information that will be reported to them by the middlemen with respect to the Trust Units. Any generic tax information provided by the Trustee of the Trust is intended to be used only to assist Trust unitholders in the preparation of their federal and state income tax returns.

Available Trust Tax Information and U.S. Federal Income Tax Rates

In compliance with the Treasury regulations reporting requirements for non-mortgage widely-held fixed investment trusts and the dissemination of Trust tax reporting information, the Trustee provides a generic tax information reporting booklet which is intended to be used only to assist Trust unitholders in the preparation of their 2013 federal and state income tax returns. This tax information booklet can be obtained at www.pacificcoastoiltrust.com.

Under current law, the highest marginal U.S. federal income tax rate applicable to ordinary income of individuals is 39.6%, and the highest marginal U.S. federal income tax rate applicable to long-term capital gains (generally, gains from the sale or exchange of certain investment assets held for more than one year) and qualified dividends of individuals is 20%. The highest marginal U.S. federal income tax rate applicable to corporations is 35%, and such rate applies to both ordinary income and capital gains.

Section 1411 of the Code imposes a 3.8% Medicare tax on certain investment income earned by individuals, estates, and trusts for taxable years beginning after December 31, 2012. For these purposes, investment income generally will include a unitholder's allocable share of the trust’s interest and royalty income plus the gain recognized from a sale of Trust Units. In the case of an individual, the tax is imposed on the lesser of (i) the individual’s net investment income from all investments, or (ii) the amount by which the individual’s modified adjusted gross income exceeds specified threshold levels depending on such individual’s federal income tax filing status. In the case of an estate or trust, the tax is imposed on the lesser of (i) undistributed net investment income, or (ii) the excess adjusted gross income over the dollar amount at which the highest income tax bracket applicable to an estate or trust begins.

California State Tax Matters

At the time of the formation of the Trust, PCEC obtained a two-year waiver from the State of California of the requirement to withhold 7% of the amounts paid to the Trust that are attributable to the Conveyed Interests held by unitholders not qualifying for an exemption from withholding. PCEC agreed to use its commercially reasonable efforts to maintain such waiver, including by seeking a renewal of such waiver prior to its expiration under California law. PCEC has received a renewal of the waiver for the years 2014 and 2015. PCEC may not be able to obtain such a waiver in the future, in which case PCEC would be required to withhold such amounts. Unless extended, the waiver will expire on December 31, 2015, and the Trust will be required to begin withholding beginning with the distribution expected to be paid in January 1, 2016.

Environmental Matters and Regulation

General. PCEC's oil and natural gas exploration and production operations are subject to stringent and comprehensive federal, regional, state and local laws and regulations governing the release, discharge or emission of materials into the environment, the handling of hazardous substances or otherwise relating to environmental protection. These laws and regulations may impose significant obligations on PCEC's operations, including requirements to:

- obtain permits to conduct regulated activities;
- limit or prohibit drilling activities in sensitive areas, such as wetlands, streams, coastal regions or areas that may contain endangered or threatened species or their habitats;
- properly manage and dispose of waste and restrict the types, quantities and concentrations of materials that can be released into the environment in the performance of drilling and production activities;
- initiate investigatory and remedial measures to mitigate pollution from former or current operations, such as restoration of drilling pits and plugging of abandoned wells;
- apply specific health and safety criteria addressing worker protection; and
- plug and abandon wells and restore properties upon which wells are drilled.

Failure to comply with environmental laws and regulations may result in the assessment of administrative, civil and criminal sanctions, including monetary penalties, the imposition of joint and several liability, investigatory and remedial obligations, and the issuance of injunctions limiting or prohibiting some or all of PCEC's operations. Moreover, these laws, rules and regulations may restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry may increase the cost of doing business in the industry and may consequently affect profitability. PCEC believes that it is in material compliance with all existing environmental laws and regulations applicable to its current operations. However, the clear trend in environmental law and regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly construction, drilling, water management, completion, emission or discharge limits or waste handling, disposal or remediation obligations could have a material adverse effect on PCEC's development expenses, results of operations and financial position. PCEC may be unable to pass on such increases to its customers. Moreover, accidental releases or spills may occur in the course of PCEC's operations, and there can be no assurance that PCEC will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products in the environment. PCEC's inability to obtain future discretionary permits could limit the future performance of the Conveyed Interests.

The following is a summary of certain existing environmental, health and safety laws and regulations, each as amended from time to time, to which PCEC's business operations are subject.

Hazardous substance and wastes. The Comprehensive Environmental Response, Compensation and Liability Act, or "CERCLA," also known as the Superfund law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. Under CERCLA, these "responsible persons" may include the owner or operator of the site where the release occurred, and entities that transport, dispose of or arrange for the transport or disposal of hazardous substances released at the site. These responsible persons may be subject to joint and several strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the U.S. Environmental Protection Agency ("EPA") and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur.

The Resource Conservation and Recovery Act ("RCRA") and comparable state laws regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the delegations of authority from the EPA, most states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, production and development of crude oil or natural gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes ("E&P Wastes") now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in the costs to manage and dispose of wastes, which could have a material adverse effect on the cash distributions to the Trust unitholders. PCEC may, from time to time generate hazardous waste which is subject to RCRA. Such wastes are properly tested, characterized and disposed of according to state and federal regulations.

The real properties upon which PCEC conducts its operations have been used for oil and natural gas exploration and production for many years. Although PCEC may have utilized operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons and wastes may have been disposed of or released at or from the real properties upon which PCEC conducts its operations, or at or from other, offsite locations, where these petroleum hydrocarbons and wastes have been taken for recycling or disposal. In addition, the real properties upon which PCEC conducts its operations may have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or hydrocarbons was not under PCEC's control. These real properties and the petroleum hydrocarbons and wastes disposed or released at or from these properties may give rise to liability for PCEC pursuant to CERCLA, RCRA and analogous state laws. Under such laws, PCEC could be required to remove or remediate previously disposed wastes, to clean up contaminated property and to perform remedial operations such as restoration of pits and plugging of abandoned wells to prevent future contamination or to pay some or all of the costs of any such action.

At the Orcutt Diatomite properties, the cyclic steam stimulation technique has the effect of stimulating the release of low-specific-gravity hydrocarbons from the outcrop formation, which manifest at the surface in a series of small "seeps." PCEC periodically inspects this surface formation for seeps, and notifies appropriate authorities when one is located. PCEC uses a French drain system to contain and collect these hydrocarbons under agency supervision. The hydrocarbons collected from the seeps are marketed along with PCEC's other production from its Orcutt properties.

Water discharges. The Federal Water Pollution Control Act, also known as the "Clean Water Act," and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. Spill prevention, control and countermeasure ("SPCC") plan requirements imposed under the Clean Water Act require appropriate containment berms and similar structures to help prevent the contamination of waters of the United States in the event of a hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws required individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. The Oil Pollution Act of 1990, as amended ("OPA"), amends the Clean Water Act and establishes strict liability and natural resource damages liability for unauthorized discharges of oil into waters of the United States. OPA requires owners or operators of certain onshore facilities to prepare Facility Response Plans for responding to a worst case discharge of oil into waters of the United States.

In addition, naturally occurring radioactive material ("NORM") is at times brought to the surface in connection with oil and gas production. Concerns have arisen over traditional NORM disposal practices (including discharge through publicly owned treatment works into surface waters), which may increase the costs associated with management of NORM.

Air Emissions. The Clean Air Act, and comparable state laws, regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. For example, in August 2012, the EPA adopted new rules that establish new air emission control requirements for oil and natural gas production and natural gas processing operations. The new rules include New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The new regulations require the reduction of VOC emissions from oil and natural gas production facilities by mandating the use of "green completions" for hydraulic fracturing, which requires the operator to recover or treat rather than vent the gas and NGLs that come to the surface during completion of the fracturing process. The rules also establish specific requirements regarding emissions from new or modified compressors, dehydrators, storage tanks, and other production equipment. In addition, the rules establish new leak detection requirements for new or modified natural gas processing plants. These laws and regulations may require PCEC to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or incur development expenses to install and utilize specific equipment or technologies to control emissions.

Compliance with these rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business. States can impose air emissions limitations that are more stringent than the federal standards imposed by the EPA, and California air quality laws and regulations are in many instances more stringent than comparable federal laws and regulations. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. Regulatory requirements relating to air emissions are particularly stringent in Southern California.

Climate change. In December 2009, the EPA determined that emissions of carbon dioxide, methane and other greenhouse gases ("GHG") 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. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of GHG under existing provisions of the federal Clean Air Act. The EPA has adopted two sets of rules regulating GHG emissions under the Clean Air Act, one of which requires a reduction in emissions of GHG from motor vehicles and the other of which regulates emissions of GHG from certain large stationary sources, effective January 2011. The EPA has also adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, as well as certain onshore oil and natural gas production facilities, on an annual basis.

In addition, Congress has from time to time considered adopting legislation to reduce emissions of GHG and almost one-half of the states have already taken legal measures to reduce emissions of GHG primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal.

California has been one of the leading states in adopting GHG emission reduction requirements, and California's cap and trade program's first compliance period began in January 1, 2012, and legally enforceable compliance obligations began with 2013 emissions. Because oil production operations emit GHGs, PCEC's operations in California are subject to regulations issued under AB32. These regulations increase PCEC's costs for those operations and adversely affect its operating results and the amount of net profits it pays to the Trust. In connection with our compliance with the California GHG Cap-and-Trade Regulation, PCEC purchased $1.4 million of GHG allowances in 2013 auctions. Although it is not possible at this time to predict when Congress may pass climate change legislation, any future federal or state laws that may be adopted to address GHG emissions could require PCEC to incur increased operating costs and could adversely affect demand for the oil and natural gas PCEC produces.

In addition, on December 15, 2009, the EPA published its findings that emissions of GHGs present an endangerment to public health and the environment. These findings allow the EPA to adopt and implement regulations that restrict emissions of GHGs under existing provisions of the federal Clean Air Act. The EPA has adopted regulations that limit emissions of GHGs from motor vehicles beginning with the 2012 model year. On June 3, 2010, the EPA also published regulations to address the permitting of GHG emissions from stationary sources under PSD and Title V permitting programs. On June 26, 2012, the U.S. Circuit Court for the District of Columbia upheld EPA's GHG regulations. In addition, on November 30, 2010, the EPA published its final rule expanding the existing GHG monitoring and reporting rule to include onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities. These requirements became applicable in 2012 for emissions occurring in 2011, but industry groups have filed suit challenging certain provisions of the rules and are engaged in settlement negotiations to amend and correct the rules. The Underlying Properties may be subject to these requirements or become subject to them in the future.

Because regulation of GHG emissions is relatively new, further regulatory, legislative and judicial developments are likely to occur. Such developments may affect how these GHG initiatives will impact PCEC's operations. In addition to these regulatory developments, recent judicial decisions that have allowed certain tort claims alleging property damage to proceed against GHG emissions sources may increase PCEC's litigation risk for such claims. The adoption of any future regulations that require reporting of GHGs or otherwise limit emissions of GHGs from the equipment and operations of PCEC could require PCEC to incur costs to monitor and report on GHG emissions or reduce emissions of GHGs associated with its operations, and such requirements also could adversely affect demand for the oil and natural gas that PCEC produces.

Legislation or regulations that may be adopted to address climate change could also affect the markets for PCEC's products by making its products more or less desirable than competing sources of energy. To the extent that its products are competing with higher GHG emitting energy sources, PCEC's products would become more desirable in the market with more stringent limitations on GHG emissions. To the extent that its products are competing with lower GHG emitting energy, PCEC's products would become less desirable in the market with more stringent limitations on GHG emissions. PCEC cannot predict with any certainty at this time how these possibilities may affect its operations.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events. If any such effects were to occur, they could adversely affect or delay demand for the oil or natural gas produced by PCEC or otherwise cause PCEC to incur significant costs in preparing for or responding to those effects.

National Environmental Policy Act and California Environmental Quality Act. Oil and natural gas exploration, development and production activities on federal lands are subject to the National Environmental Policy Act, as amended ("NEPA"). Some of PCEC's production, most notably from the Sawtelle property, is located on federally-administered land and therefore permits or authorizations issued for this field may be subject to NEPA. NEPA requires federal agencies, including the Department of the Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. This process has the potential to delay the development of oil and natural gas projects.

Similarly, the California Environmental Quality Act ("CEQA") imposes similar requirements on California state and local agencies to review environmental impacts from their proposed approvals and to develop and impose mitigation measures appropriate to reduce such impacts to insignificance where feasible. All of the Underlying Properties are located in California and are therefore subject to CEQA to the extent discretionary permits or approvals are required from California state or local agencies. In particular, PCEC's plan to increase production in the Orcutt Diatomite beyond the currently-permitted wells will require additional permits and approvals from various state, federal and local agencies, in addition to a new review under CEQA, possibly including an environmental impact report. Such a process could take many months or longer, and there can be no assurance that such permits would be timely obtained or on terms and conditions consistent with PCEC's proposed plan.

Endangered Species Act. The federal Endangered Species Act ("ESA") restricts activities that may affect endangered and threatened species or their habitats. The presence of endangered species or designation of previously unidentified endangered or threatened species could cause PCEC to incur additional costs or become subject to operating delays, restrictions or bans in the affected areas, including the obligation to obtain permits from the United States Fish & Wildlife Service ("FWS") or the California Department of Fish & Game with respect to one or more such species. For example, as a result of a settlement reached in 2011, the FWS is required to make a determination on the listing of more than 250 species as endangered or threatened over the next several years. Certain protected species are known to occur on PCEC's Orcutt and East Coyote properties, and others may yet be found or proposed for protection at one or more of the Underlying Properties. While some of PCEC's facilities or leased acreage may be located in areas that are or will be designated as habitat for endangered or threatened species, PCEC believes that it is currently in substantial compliance with the ESA.

Employee health and safety. The operations of PCEC 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, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens. PCEC believes that it is in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Where You Can Find Other Information

The Trust makes certain filings with the Securities and Exchange Commission (the "SEC"), including its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments and exhibits to those reports, available free of charge through its website, www.pacificcoastoiltrust.com, as soon as reasonably practicable after the date they are filed with, or furnished to, the SEC. The filings are also available at the SEC's Public Reference Room at 100 F Street, NE, Washington, D.C. 20549 or by calling 1-800-SEC-0330. These filings are also available through the SEC's website, www.sec.gov. The Trust's press releases and recent investor presentations are also available on the Trust's website.

Item 1A. Risk Factors.

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

The Trust's reserves and monthly cash distributions are highly dependent upon the prices realized from the sale of oil and natural gas. Prices of oil and natural gas can fluctuate widely in response to a variety of factors that are beyond the control of the Trust and PCEC. These factors include, among others:

- regional, domestic and foreign supply and perceptions of supply of oil and natural gas;
- the level of demand and perceptions of demand for oil and natural gas;
- political conditions or hostilities in oil and natural gas producing countries;
- anticipated future prices of oil and natural gas and other commodities;
- weather conditions and seasonal trends;
- technological advances affecting energy consumption and energy supply;
- U.S. and worldwide economic conditions;
- the price and availability of alternative fuels;

- the proximity, capacity, cost and availability of gathering and transportation facilities;
- the volatility and uncertainty of regional pricing differentials;
- governmental regulations and taxation;
- energy conservation and environmental measures;
- level and effect of trading in commodity futures markets, including by commodity price speculators; and
- acts of force majeure.

In 2013, ICE Brent oil prices ranged from $96.84 per Bbl to $118.90 per Bbl. In 2012, ICE Brent oil prices ranged from $88.69 per Bbl to $128.14 per Bbl. In 2013, Henry Hub natural gas prices ranged from $3.08 per MMBtu to $4.52 per MMBtu. In 2012, Henry Hub natural gas prices ranged from $1.95 per MMBtu to $3.54 per MMBtu. Profits to which the Trust is entitled are especially sensitive to the change in the price of oil, because oil is a high percentage of production from the Underlying Properties and was 97% of production in 2013.

Changes in the prices of oil and natural gas may reduce profits to which the Trust is entitled and may ultimately reduce the amount of oil and natural gas that is economic to produce from the Underlying Properties. As a result, PCEC or any third-party operator could determine during periods of low commodity prices to shut in or curtail production from wells on the Underlying Properties. In addition, PCEC or any third-party operator could determine during periods of low commodity 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, PCEC or any third-party operator may abandon any well or property if it reasonably believes that the well or property can no longer produce oil or natural gas in commercially paying quantities. This could result in termination of any Conveyed Interest relating to the abandoned well or property.

The Underlying Properties are sensitive to decreasing commodity prices. The commodity price sensitivity is due to a variety of factors that vary from well to well, including the costs associated with water handling and disposal, chemicals, surface equipment maintenance, downhole casing repairs and reservoir pressure maintenance activities that are necessary to maintain production. As a result, a decrease in commodity prices may cause the expenses of certain wells to exceed the well’s revenue. If this scenario were to occur, PCEC or any third-party operator may decide to shut-in the well or plug and abandon the well. This scenario could reduce future cash distributions to Trust unitholders. In addition, PCEC is also sensitive to increasing natural gas prices at its Orcutt properties, where it consumes natural gas in connection with its production of oil. Accordingly, at times when PCEC is a net buyer of natural gas, increases in the price of natural gas may reduce proceeds from production from PCEC’s Orcutt Diatomite properties and could reduce future cash distributions to Trust unitholders.

Actual reserves and future production may be less than engineers’ 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 depends upon, among other things, the accuracy of the reserves and future production estimated to be attributable to the Trust’s interest in the Underlying Properties as summarized in the reports the Trust obtains from its independent petroleum engineers. It is not possible to measure underground accumulations of oil and natural gas in an exact way, and estimating reserves is inherently uncertain. Ultimately, actual production and revenues for the Underlying Properties could vary both positively and negatively and in material amounts from estimates. Furthermore, direct operating expenses and development expenses relating to the Underlying Properties could be substantially higher than current estimates. Petroleum engineers are required to make subjective estimates of underground accumulations of oil and natural gas based on factors and assumptions that include:

- historical production from the area compared with production rates from other producing areas;
- oil and natural gas prices, production levels, Btu content, production expenses, transportation costs, severance and excise taxes and development expenses; and
- the assumed effect of expected governmental regulation and future tax rates.

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

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

The process of developing oil and natural gas wells and producing oil and natural gas on the Underlying Properties is subject to numerous risks beyond the Trust's or PCEC's control, including risks that could delay PCEC's or other third-party operators' current drilling or production schedule and the risk that drilling will not result in commercially viable oil or natural gas production. PCEC is not obligated to undertake any development activities, and, as a result, any drilling or completion activities will be subject to the reasonable discretion of PCEC. PCEC's plan to increase production in the Orcutt Diatomite and West Pico properties beyond the currently permitted wells will require additional permits and approvals from various state and local agencies. There can be no assurances that such permits will be issued in a timely manner or at all. Additionally, the ability of PCEC or any third-party operator to carry out operations or to finance planned development expenses could be materially and adversely affected by any factor that may curtail, delay, reduce or cancel development and production, including:

- delays imposed by or resulting from compliance with regulatory requirements, including permitting;
- unusual or unexpected geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- lack of available gathering facilities or delays in construction of gathering facilities;
- lack of available capacity on interconnecting transmission pipelines;
- equipment malfunctions, failures or accidents;
- unexpected operational events and drilling conditions;
- reductions in oil or natural gas prices;
- market limitations for oil or natural gas;
- pipe or cement failures;
- casing collapses;
- lost or damaged drilling and service tools;
- loss of drilling fluid circulation;
- uncontrollable flows of oil and natural gas, insert gas, water or drilling fluids;
- fires and natural disasters;
- environmental hazards, such as oil and natural gas leaks, pipeline ruptures and discharges of toxic gases;
- adverse weather conditions; and
- oil or natural gas property title problems.

In the event that planned operations, including drilling of development wells, are delayed or cancelled, or existing wells or development wells have lower than anticipated production due to one or more of the factors above or for any other reason, distributions to Trust unitholders may be reduced. Further, in the event PCEC or any third-party operator incurs increased costs due to one or more of the above factors or for any other reason and is not able to recover such costs from insurance, distributions to Trust unitholders may be reduced.

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

The Trust Units are a passive investment that entitle the Trust unitholder only to receive cash distributions from the Conveyed Interests and commodity derivative contracts. Trust unitholders have no voting rights with respect to PCEC and, therefore, have no managerial, contractual or other ability to influence PCEC's activities or the operations of the Underlying Properties. PCEC operated approximately 99% of the average daily production from the Underlying Properties for the year ended December 31, 2013 and is generally responsible for making all decisions relating to drilling activities, sale of production, compliance with regulatory requirements and other matters that affect such properties. Accordingly, PCEC may take actions that are in its own interest that may be different from the interests of the Trust.

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

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

PCEC may transfer all or a portion of the Underlying Properties at any time without Trust unitholder consent.

PCEC may at any time transfer all or part of the Underlying Properties, subject to and burdened by the applicable Conveyed Interests, and may abandon individual wells or properties reasonably believed to be uneconomic. Trust unitholders are not entitled to vote on any transfer or abandonment of the Underlying Properties, and the Trust will not receive any profits from any such transfer. Following any sale or transfer of any of the Underlying Properties, the applicable Net Profits Interest and if applicable, the Royalty Interest, will continue to burden the transferred property and net profits and royalties attributable to such transferred property will be calculated for such transferred property on a standalone basis using the computation of net profits and royalties set forth in the Conveyance related to the Conveyed Interests. PCEC may delegate to the transferee responsibility for all of PCEC's obligations relating to the applicable Conveyed Interests on the portion of the Underlying Properties transferred.

PCEC may, without the consent of the Trust unitholders, require the Trust to release the Conveyed Interests associated with any property that accounts for less than or equal to 0.25% of the total production from the Underlying Properties in the prior twelve months and provided that the Conveyed Interests covered by such releases cannot exceed, during any twelve month period, an aggregate fair market value to the Trust of $500,000. These releases will be made only in connection with a sale by PCEC of the relevant Underlying Properties and are conditioned upon an amount equal to the fair market value (net of sales costs) of such Conveyed Interests being treated as an offset amount against costs and expenses.

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

The reserves attributable to the Underlying Properties 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, NPI or royalty interests to replace the depleting assets and production. Therefore, proceeds to the Trust and cash distributions to Trust unitholders will decrease over time.

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

Future maintenance projects on the Underlying Properties may affect the quantity of proved reserves that can be economically produced from wells on the Underlying Properties. The timing and size of these projects will depend on, among other factors, the market prices of oil and natural gas. Furthermore, with respect to properties for which PCEC is not designated as the operator, PCEC has limited control over the timing or amount of those development expenses. PCEC also has the right to non-consent and not participate in the development expenses on properties for which it is not the operator, in which case PCEC and the Trust will not receive the production resulting from such development expenses until after payout occurs pursuant to the applicable joint operating agreements. If PCEC or any third-party operator does not implement maintenance projects when warranted, the future rate of production decline of proved reserves may be higher than the rate currently expected by PCEC or estimated in the reserve reports.

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

Because the net profits and royalties payable to the Trust are derived from the sale of depleting assets, the portion of the distributions to Trust unitholders attributable to depletion may be considered to have the effect of a return of capital as opposed to a return on investment. Eventually, the Underlying Properties burdened by the Conveyed Interests may cease to produce in commercially paying quantities and the Trust may, therefore, cease to receive any distributions of net profits and royalties therefrom.

A change in oil price differentials may adversely impact the cash distributions available to Trust unitholders.

PCEC's oil production is sold in the local markets where the pricing is based on local or regional supply and demand factors. The difference between the benchmark price and the price PCEC receives is called a differential. PCEC cannot predict how the differential applicable to its production will change in the future, and it is possible that the differentials will change and the prices received for PCEC's oil production may decrease. Numerous factors may influence local pricing, such as refinery capacity, pipeline capacity and specifications, upsets in the mid-stream or downstream sectors of the industry, trade restrictions and governmental regulations. Changes in the differential between common benchmark prices for oil and the wellhead price PCEC receives could adversely impact the cash distributions available to Trust unitholders.

In 2013, Phillips 66 purchase of production from the Orcutt properties is pursuant to a sales contract between Phillips 66 and PCEC that expires on December 31, 2015 and includes an option to renegotiate prices. Its purchase of production from West Pico properties is pursuant to a month-to-month sales contract.

The amount of cash available for distribution by the Trust is reduced by the amount of any costs and expenses related to the Underlying Properties and other costs and expenses incurred by the Trust.

The Trust indirectly bears an 80% share of all costs and expenses related to the production from the Developed Properties and a 25% share of all costs and expenses related to the production from the Remaining Properties. These costs and expenses include direct operating expenses and development expenses, which reduce the amount of cash received by the Trust and thereafter distributable to Trust unitholders. Accordingly, higher costs and expenses related to the Underlying Properties will directly decrease the amount of cash received by the Trust in respect of a Net Profits Interest. Historical costs may not be indicative of future costs. For example, PCEC may in the future propose additional drilling projects that significantly increase the capital expenditures associated with the Underlying Properties, which could reduce cash available for distribution by the Trust. In addition, cash available for distribution by the Trust is further reduced by the Trust's general and administrative expenses and by the PCEC operating and services fee, which was originally $1,000,000 annually, and is adjusted for changes in the CPI each April 1 commencing April 1, 2013.

Net profits payable to the Trust depend upon production quantities, sales prices of oil and natural gas and costs to develop and produce the oil and natural gas. Royalty Interest Proceeds depend on the Trust's share of production and property taxes and post-production costs, if any. If at any time cumulative costs for the Developed Properties or the Remaining Properties exceed cumulative gross proceeds associated with such properties, neither the Trust nor the Trust unitholders would be liable for the excess costs, but the Trust would not receive any net profits from the Developed Properties or the Remaining Properties, as the case may be, until cumulative gross proceeds for such properties exceed the cumulative total excess costs for such properties.

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

The marketability of PCEC's oil and natural gas production depends in part upon the availability, proximity and capacity of gathering, transportation and processing facilities owned by third parties. In general, PCEC does not control these third-party facilities and its access to them may be limited or denied due to circumstances beyond its control. A significant disruption in the availability of these facilities could adversely impact PCEC's ability to deliver to market the oil and natural gas it produces and thereby cause a significant interruption in PCEC's operations. In some cases, PCEC's ability to deliver to market its oil and natural gas is dependent upon coordination among third parties who own the transportation and processing facilities it uses, and any inability or unwillingness of those parties to coordinate efficiently could also interrupt PCEC's operations. These are risks for which PCEC generally does not maintain insurance.

The facilities at PCEC's West Pico, East Coyote and Sawtelle properties are located in urban settings. The available means for alternative transportation of production from these properties are limited, due to the difficulties of building transportation systems in these areas as well as permitting restrictions pertaining to trucking. In addition, PCEC's Orcutt properties are currently serviced by a single gathering system, and there are a limited number of other transportation alternatives in the area. A change in PCEC's current takeaway arrangements, in the absence of satisfactory alternatives, would have an adverse effect on PCEC's operations. PCEC would be similarly affected if any of the other transportation, gathering and processing facilities it uses became unavailable or unable to provide services.

Phillips 66 purchases a significant percentage of PCEC's production, and a decision by Phillips 66 to discontinue or reduce its purchases of PCEC's production may adversely impact the cash distributions available to Trust unitholders.

In 2013, Phillips 66 purchased 94% of PCEC's production. Phillips 66's purchase of oil production from the Orcutt properties is pursuant to a sales contract between Phillips 66 and PCEC that expires on December 31, 2015, and its purchase of oil production from the Sawtelle and West Pico properties is pursuant to a month-to-month contract. If Phillips 66 were to no longer purchase PCEC's production, or were to significantly reduce the amount of production it purchases, the cash distributions available to Trust unitholders may be adversely impacted.

The Trustee must sell the Conveyed Interests and dissolve the Trust prior to the expected termination of the Trust if the holders of at least 75% of the outstanding Trust Units approve the sale or vote to dissolve the Trust or if the cash available for distribution to the Trust is less than $2.0 million for each of any two consecutive years. As a result, Trust unitholders may not recover their investment.

The Trustee must sell the Conveyed Interests and dissolve the Trust if the holders of at least 75% of the outstanding Trust Units approve the sale or vote to dissolve the Trust. The Trustee must also sell the Conveyed Interests and dissolve the Trust if the cash available for distribution to the Trust is less than $2.0 million for each of any two consecutive years. The net profits of any such sale will be distributed to the Trust unitholders.

Recent regulatory changes in California have and may continue to negatively impact PCEC's production in its Diatomite properties.

Recent regulatory changes in California have impacted PCEC's Diatomite production. In 2010, Diatomite production decreased significantly due to the inability to drill new wells pending the receipt of permits from the California Department of Conservation, Division of Oil, Gas, and Geothermal Resources, or "DOGGR." PCEC has approval under these new regulations for its current 96-well Diatomite drilling program, though the drilling of additional wells will require additional approval. The current approval, among other things, includes stringent operating, response and preventative requirements relating to mechanical integrity testing and responses to integrity issues and surface expressions, among others. Compliance with these requirements and delays in regulatory reviews, as well as other regulatory action and inaction, may negatively impact the pace of drilling and steam injection and may impact development from PCEC's Diatomite properties in the near term. PCEC may not be successful in streamlining the review process with the DOGGR or in taking additional steps to more efficiently manage operations to avoid additional delays. PCEC's production activities in the Diatomite zone have resulted in crude oil from the near-surface Careaga zone reaching the surface in various locations in the Orcutt field. PCEC controls such surface expressions by balancing the amount of fluids injected and withdrawn into the Diatomite zone. However, in areas where surface expressions still occur, the crude oil is collected through a surface gathering system. In addition, two wells in the field have developed casing leaks that allowed steam to reach the surface. Steaming operations in several Diatomite wells had to be suspended for periods of time during 2011 while surface expressions were being investigated or changes made to nearby well configurations. The DOGGR may impose additional operational restrictions or requirements, including requiring that wells be shut in, as a result of incidents involving surface expressions. PCEC is allowed to produce at its Orcutt properties despite surface expressions pursuant to a field order issued by DOGGR. This field order is subject to change or revocation by DOGGR at its sole discretion.

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

The existence of a material title deficiency with respect to the Underlying Properties could reduce the value of a property or render it worthless, thus adversely affecting the Conveyed Interests and the distributions to Trust unitholders. PCEC does not obtain title insurance covering mineral leaseholds, and PCEC's failure to cure any title defects may cause PCEC to lose its rights to production from the Underlying Properties. In the event of any such material title problem, profits available for distribution to Trust unitholders and the value of the Trust Units may be reduced.

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

PCEC holds an aggregate of 3,866,497 Trust Units. PCEC may sell Trust Units in the public or private markets, and any such sales could have an adverse impact on the price of the Trust Units. The Trust has granted registration rights to PCEC, which, when exercised, facilitate sales of Trust Units by PCEC. For example, in September 2013, PCEC and Other Selling Unitholders sold 13,500,000 Trust Units at a price to the public of $17.10 per Trust Unit. As of March 14, 2014, the price per Trust Unit is $13.13.

The trading price for the Trust Units may not reflect the value of the Conveyed Interests held by the Trust, which would adversely affect the return on an investment in the units.

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

Conflicts of interest could arise between PCEC and its affiliates, on the one hand, and the Trust and the Trust unitholders, on the other hand, which could harm the business or financial results of the Trust.

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

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

- PCEC may sell some or all of the Underlying Properties without taking into consideration the interests of the Trust unitholders. Such sales may not be in the best interests of the Trust unitholders and the purchasers may lack PCEC's experience or its credit worthiness. PCEC also has the right, under certain circumstances, to cause the Trust to release all or a portion of the Conveyed Interests in connection with a sale of a portion of the Underlying Properties to which such Conveyed Interests relates. In such an event, the Trust is entitled to receive the fair market value (net of sales costs) of the Conveyed Interests released, which will be treated as an offset amount against costs and expenses. Please read "The Underlying Properties—Sale and Abandonment of Underlying Properties."

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

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

The affairs of the Trust are managed by the Trustee. Your voting rights as a Trust unitholder are more limited than those of stockholders of most public corporations. For example, there is no requirement for the Trust to hold annual meetings of Trust unitholders or for an annual or other periodic re-election of the Trustee. The Trust does not intend to hold annual meetings of Trust unitholders. The Trust agreement provides that the Trustee may only be removed and replaced by the holders of a majority of the Trust Units present in person or by proxy at a meeting of such holders where a quorum is present, including Trust Units held by PCEC, called by either the Trustee or the holders of not less than 10% of the outstanding Trust Units. As a result, it would be difficult for public Trust unitholders to remove or replace the Trustee without the cooperation of PCEC so long as it holds a significant percentage of total Trust Units.

Trust unitholders have limited ability to enforce provisions of the Conveyance creating the Conveyed Interests, and PCEC's liability to the Trust is limited.

The Trust agreement permits the Trustee to sue PCEC or any other future owner of the Underlying Properties to enforce the terms of the Conveyance creating the Conveyed Interests. If the Trustee does not take appropriate action to enforce provisions of the Conveyance, Trust unitholders' recourse would be limited to bringing a lawsuit against the Trustee to compel the Trustee to take specified actions. The Trust agreement expressly limits a Trust unitholder's ability to directly sue PCEC or any other third party other than the Trustee. As a result, Trust unitholders are not able to sue PCEC or any future owner of the Underlying Properties to enforce these rights. Furthermore, the conveyance creating the Conveyed Interests provides that, except as set forth in the Conveyance, PCEC will not be liable to the Trust for the manner in which it performs its duties in operating the Underlying Properties as long as it acts without gross negligence or willful misconduct.

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 corporations for profit under the General Corporation Law of the State of Delaware. No assurance can be given, however, that the courts in jurisdictions outside of Delaware will give effect to such limitation.

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

The oil and natural gas exploration and production operations on the Underlying Properties are subject to stringent and comprehensive federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations that apply to the operations on the Underlying Properties, including the requirement to obtain a permit before conducting drilling, waste disposal or other regulated activities; the restriction of types, quantities and concentrations of materials that can be released into the environment; restrictions on water withdrawal and use; the incurrence of significant development expenses to install pollution or safety-related controls at the operated facilities; the limitation or prohibition of drilling activities on certain lands lying within wetlands and other protected areas; and the imposition of substantial liabilities for pollution resulting from operations. For example, the EPA has published regulations that impose more stringent emissions control requirements for oil and gas development and production operations, which may require PCEC, its operators, or third-party contractors to incur additional expenses to control air emissions from current operations and during new well developments by installing emissions control technologies and adhering to a variety of work practice and other requirements. These requirements could increase the costs of development and production, reducing the profits available to the Trust and potentially impairing the economic development of the Underlying Properties. PCEC's Orcutt and East Coyote properties are located in areas that host several endangered plant and animal species. The known presence of these endangered species may limit future operations in certain areas of the properties and will result in increased costs of development as certain procedures must be used to protect such species and costs may be incurred to provide habitat areas or substitute replacement areas.

In addition, PCEC's plan to increase production in the Diatomite formation beyond the currently permitted wells will require additional permits and approvals from various state, federal and local agencies, in addition to a new review under the CEQA. Such a process could take many months or possibly longer, and there can be no assurance that such permits would be timely obtained or on terms and conditions consistent with PCEC's proposed plan.

For all of PCEC's operations, numerous governmental authorities such as the EPA, analogous state agencies such as the DOGGR and local agencies such as the County of Santa Barbara Planning and Development, Energy Division, have the power to enforce compliance with these laws and regulations and the permits issued under them, often times requiring difficult and costly actions. Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties; the imposition of investigatory or remedial obligations; and the issuance of injunctions limiting or preventing some or all of the operations on the Underlying Properties. Furthermore, the inability to comply with environmental laws and regulations in a cost-effective manner, such as removal and disposal of produced water and other generated oil and gas wastes, could impair PCEC's ability to produce oil and natural gas commercially from the Underlying Properties, which would reduce profits and royalties attributable to the Conveyed Interests.

There is inherent risk of incurring significant environmental costs and liabilities in the operations on the Underlying Properties as a result of the handling of petroleum hydrocarbons and wastes, air emissions and wastewater discharges related to operations, and historical industry operations and waste disposal practices. Under certain environmental laws and regulations, PCEC could be subject to joint and several strict liability for the removal or remediation of previously released materials or property contamination regardless of whether PCEC was responsible for the release or contamination or whether PCEC was in compliance with all applicable laws at the time those actions were taken. Private parties, including the owners of properties upon which wells are drilled and facilities where petroleum hydrocarbons or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. In addition, the risk of accidental spills or releases could expose PCEC to significant liabilities that could have a material adverse effect on PCEC's business, financial condition and results of operations and could reduce the amount of cash available for distribution to Trust unitholders. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly operational control requirements or waste handling, storage, transport, disposal or cleanup requirements could require PCEC to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on its results of operations, competitive position or financial condition. PCEC may be unable to recover some or any of these costs from insurance, in which case the amount of cash received by the Trust may be decreased. The Trust indirectly bears an 80% share of all costs and expenses related to the production from the Developed Properties and a 25% share of all costs and expenses related to the production from the Remaining Properties, including those related to environmental compliance and liabilities associated with the Underlying Properties, including costs and liabilities resulting from conditions that existed prior to PCEC's acquisition of the Underlying Properties unless such costs and expenses result from the operator's negligence or misconduct. In addition, as a result of the increased cost of compliance, PCEC may decide to discontinue drilling.

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

The production and development operations on the Underlying Properties are subject to complex and stringent laws and regulations. In order to conduct its operations in compliance with these laws and regulations, PCEC must obtain and maintain numerous permits, drilling bonds, approvals and certificates from various federal, state and local governmental authorities and engage in extensive reporting. PCEC may incur substantial costs and experience delays in order to maintain compliance with these existing laws and regulations, and the Trust's income is reduced by its 80% share of such costs related to the production from the Developed Properties and a 25% share of such costs related to the production from the Remaining Properties. In addition, PCEC's costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to its operations. Such costs could have a material adverse effect on PCEC's business, financial condition and results of operations and reduce the amount of cash received by the Trust in respect of the Conveyed Interests. For example, in California, there have been proposals at the legislative initiative and executive levels over the past two years for tax increases which have included a severance tax as high as 15% on all oil production in California. The County of Santa Barbara also recently considered imposing a severance tax. Although the proposals have not passed, the financial crisis in the State of California could lead to a severance tax on oil being imposed in the future. While PCEC cannot predict the impact of such a tax given the uncertainty of the proposals, the imposition of such a tax could have severe negative impacts on both its willingness and ability to incur capital expenditures to increase production, could severely reduce or completely eliminate PCEC's profit margins and would result in lower oil production in PCEC's properties due to the need to shut-in wells and facilities made uneconomic either immediately or at an earlier time than would have previously been the case. PCEC must also comply with laws and regulations prohibiting fraud and market manipulations in energy markets.

Laws and regulations governing exploration and production may also affect production levels. PCEC is required to comply with federal and state laws and regulations governing conservation matters, including:

- provisions related to the unitization or pooling of oil and natural gas properties;

- the spacing of wells;
- the plugging and abandonment of wells; and
- the removal of related production equipment.

Additionally, state and federal regulatory authorities may expand or alter applicable pipeline safety laws and regulations, compliance with which may require increased capital costs on the part of PCEC and third-party downstream oil and natural gas transporters. These and other laws and regulations can limit the amount of oil and natural gas PCEC can produce from its wells, limit the number of wells it can drill, or limit the locations at which it can conduct drilling operations, which in turn could negatively impact Trust distributions, estimated and actual future net revenues to the Trust and estimates of reserves attributable to the Trust's interests.

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

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

The oil and gas industry is a direct source of certain GHG emissions, namely carbon dioxide and methane, and future restrictions on such emissions could impact future operations on the Underlying Properties. On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the Earth's atmosphere and other climate changes. Based on these findings, the agency has begun adopting and implementing regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. The EPA has adopted rules that require a reduction in emissions of GHGs from motor vehicles as well as rules that regulate emissions of GHGs from certain large stationary sources under the Prevention of Significant Deterioration ("PSD") and Title V permitting programs. On June 26, 2012, the U.S. Circuit Court for the District of Columbia upheld EPA's GHG regulations; an appeal of that decision is currently pending before the U.S. Supreme Court. These EPA rules could affect the operations on the Underlying Properties or the ability of PCEC to obtain air permits for new or modified facilities. In addition, on November 30, 2010, the EPA published final regulations expanding the existing GHG monitoring and reporting rule to include onshore and offshore oil and natural gas production and onshore oil and natural gas processing, transmission, storage and distribution facilities. These requirements became applicable in 2012 for emissions occurring in 2011, although industry groups have filed suit challenging certain provisions of the rules and are engaged in settlement negotiations to amend and correct the rules. The Underlying Properties may be subject to these requirements or become subject to them in the future. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise limits emissions of GHGs from the equipment or operations of PCEC could require PCEC to incur costs to monitor and report on GHG emissions or reduce emissions of GHGs associated with its operations. Such requirements could also adversely affect demand for the oil and natural gas produced, all of which could reduce profits and royalties attributable to the Conveyed Interests and, as a result, the Trust's cash available for distribution.

In addition, the U.S. Congress has from time to time considered legislation to reduce emissions of GHGs, and many of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. These reductions would be expected to cause the cost of allowances to escalate significantly over time.

For example, California enacted AB32, the Global Warming Solutions Act of 2006, which established the first statewide program in the United States to limit GHG emissions and impose penalties for non-compliance. The final cap-and-trade program began on January 1, 2012, and legally enforceable compliance obligations began with 2013 emissions.

Because oil production operations emit GHGs, PCEC's operations in California are subject to regulations issued under AB32. These regulations increase PCEC's costs for those operations and adversely affect its operating results. Because regulation of GHG emissions is relatively new, further regulatory, legislative and judicial developments are likely to occur. Such developments may affect how these GHG initiatives will impact PCEC and the Trust. Due to the uncertainties surrounding the regulation of and other risks associated with GHG emissions, PCEC cannot predict the financial impact of related developments on PCEC or the Trust.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on PCEC's assets and operations and, consequently, may reduce profits and royalties attributable to the Conveyed Interests and, as a result, the Trust's cash available for distribution.

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

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

The ability to develop and operate the Underlying Properties depends on PCEC's future financial condition and economic performance and access to capital, which in turn will depend upon the supply and demand for oil and natural gas, prevailing economic conditions and financial, business and other factors, many of which are beyond the control of PCEC. PCEC is not a reporting company and is not required to file periodic reports with the SEC pursuant to the Securities Exchange Act of 1934, as amended, or the "Exchange Act." Therefore, neither the Trust unitholders nor the Trustee have access to financial information about PCEC.

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

In the event of the bankruptcy of PCEC, if a court held that the NPI were part of the bankruptcy estate, the Trust may be treated as an unsecured creditor with respect to the NPI.

PCEC and the Trust believe that the NPI would be treated as an interest in real property under the laws of the State of California. While no California case has defined the nature of a "net profits interest," the California Supreme Court has held that an overriding royalty interest in an oil and gas lease (such as the Royalty Interest) is an interest in real property. The California Supreme Court has also explained that the nature of the interest created depends upon the intention of the parties involved. Given that the NPI are defined in the Conveyance as an overriding royalty interest payable on the basis of net profits and the Conveyance states that it is the express intent of the parties that the NPI constitute, for all purposes, an interest in real property, it is likely that a California court would hold that the NPI are an interest in real property. Nevertheless, the outcome is not certain because there is no dispositive California Supreme Court case directly concluding that a conveyance of a "net profits interest" constitutes the conveyance of a real property interest. As such, in a bankruptcy of PCEC, the NPI might be considered an asset of the bankruptcy estate and used to satisfy obligations to creditors of PCEC, in which case the Trust would be an unsecured creditor of PCEC at risk of losing the entire value of the NPI to senior creditors.

Due to the Trust's lack of geographic and industry diversification, adverse developments in California could adversely impact the results of operations and cash flows of the Underlying Properties and reduce the amount of cash available for distributions to Trust unitholders.

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

The receipt of payments by PCEC based on any commodity derivative contract depends upon the financial position of commodity derivative contract counterparties. A default by any commodity derivative contract counterparties could reduce the amount of cash available for distribution to the Trust unitholders.

Payments from any commodity derivative contract counterparties to PCEC are intended to offset costs and thus have the effect of providing additional cash to the Trust during periods of lower crude oil prices. In the event that any of the counterparties to commodity derivative contracts default on their obligations to make payments to PCEC under the commodity derivative contracts, the cash distributions to the Trust unitholders could be materially reduced. PCEC does not have any security interest from its hedge counterparties against which it could recover in the event of a default by any such counterparty. The commodity derivative contracts entered into by PCEC for the production from the Underlying Properties expire March 31, 2014 and will not be replaced.

Pursuant to the Jumpstart Our Business Startups (JOBS) Act, the Trust's independent registered public accounting firm is not required to attest to the effectiveness of the Trust's internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002 for so long as the Trust is an emerging growth company and the Trust may take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act for complying with new or revised accounting standards.

The Trust is required to disclose changes made in its internal control over financial reporting on a quarterly basis and the Trustee is required to assess the effectiveness of the Trust's controls annually. However, for as long as the Trust is an "emerging growth company" under the JOBS Act, its independent registered public accounting firm is not required to attest to the effectiveness of the Trust's internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002. The Trust could be an emerging growth company for up to five years after its initial public offering. Even if the Trustee concludes that the Trust's internal controls over financial reporting are effective, the Trust's independent registered public accounting firm may still decline to attest to the Trustee's assessment or may issue a report that is qualified if it is not satisfied with the Trust's controls or the level at which the Trust's controls are documented, designed, operated or reviewed, or if it interprets the relevant requirements differently.

In addition, Section 107 of the JOBS Act also provides that an "emerging growth company" can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act for complying with new or revised accounting standards. In other words, an "emerging growth company" can delay the adoption of certain accounting standards until those standards would otherwise apply to private companies. The Trust elected to delay such adoption of new or revised accounting standards, and as a result, the Trust may not comply with new or revised accounting standards on the relevant dates on which adoption of such standards is required for non-emerging growth companies. As a result of such election, the Trust's financial statements may not be comparable to the financial statements of other public companies. The Trust may take advantage of these reporting exemptions until it is no longer an "emerging growth company." Neither PCEC nor the Trust can predict if investors will find the Trust Units less attractive because the Trust relies on these exemptions. If some investors find the Trust Units less attractive as a result, there may be a less active trading market for the Trust Units and the Trust's trading price may be more volatile.

Tax Risks Related to the Trust's Trust Units

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

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

Neither PCEC nor the Trustee has requested a ruling from the IRS regarding the tax status of the Trust, and neither PCEC nor the Trustee intends to request such a ruling or can assure you that such a ruling would be granted if requested or that the IRS will not challenge these positions on audit.

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

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

Both the Obama Administration's budget proposal for fiscal year 2014 and other recently introduced legislation include proposals that would, among other things, eliminate or reduce certain key U.S. federal income tax incentives currently available to oil and gas exploration and production companies. These changes include, but are not limited to the repeal of the percentage depletion allowance for oil and gas properties. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and gas exploration and development, could reduce the cash available for distribution to the Trust unitholders or adversely affect the value of the Trust Units.

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

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

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

If a unitholder sells 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. A substantial portion of any gain recognized may be taxed as ordinary income due to potential recapture items, including depletion recapture. Potential investors should consult with their tax advisors prior to acquiring Trust Units. Please see "United States Federal Income Tax Considerations—Tax Consequences to U.S. Trust Unitholders—Disposition of Trust Units" in the Prospectus for additional information.

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

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

As a result of investing in Trust Units, unitholders may become subject to state and local taxes and return filing requirements in California.

In addition to federal income taxes, Trust unitholders will likely be subject to other taxes, including state and local taxes that are imposed in California, where the Underlying Properties are located, even if the Trust unitholders do not live in California. Trust unitholders likely are required to file state and local income tax returns and pay state and local income taxes in California. Further, Trust unitholders may be subject to penalties for failure to comply with those requirements. It is the responsibility of each Trust unitholder to file all federal, state and local tax returns.

At the time of the formation of the Trust, PCEC obtained a two-year waiver from the State of California of the requirement to withhold 7% of the amounts paid to the Trust that are attributable to the Conveyed Interests held by unitholders not qualifying for an exemption from withholding. PCEC agreed to use its commercially reasonable efforts to maintain such waiver, including by seeking a renewal of such waiver prior to its expiration under California law. PCEC has received a renewal of the waiver for the years 2014 and 2015. PCEC may not be able to obtain such a waiver in the future, in which case PCEC would be required to withhold such amounts. Unless extended, the waiver will expire on December 31, 2015, and the Trust will be required to begin withholding beginning with the distribution expected to be paid in January 1, 2016.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

Description of the Underlying Properties

The Underlying Properties consist of producing and non-producing interests in oil units, wells and lands located onshore in California in the Santa Maria Basin, which contains PCEC's Orcutt properties, and the Los Angeles Basin, which contains PCEC's West Pico, East Coyote and Sawtelle properties.

The Underlying Properties are located in areas with significant histories of oil and natural gas production. The Santa Maria and Los Angeles Basins are some of California's longest producing oil regions. Oil reserves in the Santa Maria Basin were discovered in 1901, and the basin has produced over one billion Bbls of oil since that time. Oil reserves in the Los Angeles Basin were discovered in 1892, and the basin has produced over nine billion Bbls of oil since that time. Long producing histories in the Santa Maria and Los Angeles Basins provide for well-established production profiles and increased certainty of production estimates.

PCEC acquired its Orcutt properties in the Santa Maria Basin in 2004. PCEC operates 100% of the average daily production associated with these assets and has an average working interest and net revenue interest of approximately 98% and 95%, respectively, in its Orcutt properties. PCEC acquired its West Pico and Sawtelle properties in the Los Angeles Basin in 1993 and acquired its East Coyote properties in 1999 and 2000. PCEC operated approximately 95% of the average daily production associated with its West Pico properties in the Los Angeles Basin during 2013 and its interests in Sawtelle and East Coyote were operated by BreitBurn Operating L.P. ("BOLP"), a subsidiary of BreitBurn Energy Partners L.P.

As of December 31, 2013, the Underlying Properties had proved reserves of 32.3 MMBoe. As of December 31, 2013, approximately 71% of the volumes of the proved reserves associated with the Underlying Properties and 86% of the volumes of the proved reserves associated with the Trust were attributed to proved developed reserves. Proved developed reserves are the most valuable and lowest risk category of reserves because their production requires no significant future development expenses. In addition, 100% of the Underlying Properties are held by production or owned in fee. For the year ended December 31, 2013, the average net sales (after royalties and other interests) were approximately 3,565 Boe/d from the Underlying Properties and 814 Boe/d from the Remaining Properties. The Underlying Properties are comprised of approximately 99% oil and the Remaining Properties are comprised of 100% oil.

PCEC's interests in the Underlying Properties require PCEC to bear its proportionate share of the costs of development and operation of such properties. The Underlying Properties are burdened by non-cost bearing interests owned by third parties consisting primarily of overriding royalty and royalty interests.

Reserves

Netherland, Sewell & Associates, Inc. ("NSAI"), independent petroleum and geological engineers, estimated crude oil, NGL and natural gas proved reserves of the Underlying Properties' full economic life and for the Trust life as of December 31, 2013. Numerous uncertainties are inherent in estimating reserve volumes and values, and the estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of the reserves may vary significantly from the original estimates. The technical person primarily responsible for overseeing the preparation of the reserve estimates and the third-party reserve reports is Mark L. Pease, the Chief Operating Officer of PCEC's General Partner. Mr. Pease received a Bachelor of Science in Petroleum Engineering from the Colorado School of Mines in 1979. Prior to joining PCEC's General Partner, Mr. Pease was Senior Vice President, E&P Technology & Services for Anadarko Petroleum Corporation. Mr. Pease has over 31 years of experience working in various capacities in the energy industry, including acquisition analysis, reserve estimation, reservoir engineering and operations engineering. Mr. Pease consults with NSAI during the reserve estimation process to review properties, assumptions and relevant data.

See Appendix A to this report for the estimates of proved reserves provided by NSAI. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report included in this report are Mr. J. Carter Henson, Jr. and Mr. Mike K. Norton. Mr. Henson has been practicing consulting petroleum engineering at NSAI since 1989. He is a Licensed Professional Engineer in the State of Texas (License No. 73964) and has over 31 years of practical experience in petroleum engineering, with over 23 years of experience in the estimation and evaluation of reserves. He graduated from Rice University in 1981 with a Bachelor of Science Degree in Mechanical Engineering. Mr. Mike K. Norton has been practicing consulting petroleum geology at NSAI since 1989. Mr. Norton is a Licensed Petroleum Geologist in the State of Texas (License No. 441) and has over 35 years of practical experience in petroleum geosciences, with over 30 years of experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1978 with a Bachelor of Science Degree in Geology. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

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

The following table summarizes the estimated proved reserve quantities and discounted future net cash flows attributable to the Trust and Underlying Properties as of December 31, 2013:

	Trust Net Profits Interests				Underlying Properties			
	Oil(a) (MBbl)	**Natural Gas (MMcf)**	**Total (MBoe)**	**Discounted Future Net Cash Flows (in thousands)**	**Oil(a) (MBbl)**	**Natural Gas (MMcf)**	**Total (MBoe)**	**Discounted Future Net Cash Flows (in thousands)**
Proved								
Developed Properties	8,544.9	1,636.3	8,817.6	$ 407,703.9	18,511.0	3,437.6	19,084.0	$ 513,306.1
Remaining Properties—Developed	706.0	2.5	706.4	37,753.4	3,868.8	18.7	3,871.9	160,963.5
Remaining Properties—Undeveloped	1,579.6	—	1,579.6	56,364.8	9,380.7	—	9,380.7	199,591.6
Total Proved	**10,830.5**	**1,638.8**	**11,103.6**	**$ 501,822.1**	**31,760.8**	**3,456.3**	**32,336.6**	**$ 873,861.2**

(a) Estimated proved reserves of oil include condensate and natural gas liquids.

Proved undeveloped reserves decreased by 29 MBoe to 1,580 MBoe at the end of 2013 compared to 1,609 MBoe at the end of 2012. There were no conversions of proved undeveloped reserves to developed reserves during the year ended December 31, 2013. As of December 31, 2013, there were no estimated proved undeveloped reserves that have remained undeveloped for more than five years, and it is expected that all estimated proved undeveloped reserves will be developed within the next five years.

The Financial Accounting Standards Board requires supplemental disclosures for oil and gas producers based on a standardized measure of discounted future net cash flows relating to proved oil and gas reserve quantities. Under this disclosure, future cash inflows are computed by applying the average prices during the 12-month period prior to fiscal year-end, determined as an unweighted arithmetic average of the first-day-of-the-month benchmark price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. Future price changes are only considered to the extent provided by contractual arrangements in existence at year end. The standardized measure of discounted future net cash flows is achieved by using a discount rate of 10% a year to reflect the timing of future cash flows relating to proved oil and gas reserves.

The changes in standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves attributable to the Trust for the period from May 8 to December 31, 2013 are as follows:

Thousands of dollars	Year Ended December 31, 2013	May 8 through December 31, 2012
Beginning balance	$ 538,543	$ —
Conveyance of NPI from PCEC	—	441,166
Net change in sales and transfer prices, net of production expense	21,483	(19,069)
Accretion of discount	53,854	29,411
Revisions of previous estimates and other	(46,576)	125,990
Income from conveyed interests	(65,481)	(38,955)
Standardized measure	$ 501,822	$ 538,543

The average adjusted production prices weighted by production over the remaining lives of the properties are $100.51 per barrel of oil and $4.11 per MCF of gas for net proved reserves attributable to the Trust. The average adjusted production prices weighted by production over the remaining lives of the properties are $99.40 per barrel of oil and $4.16 per MCF of gas for net proved reserves attributable to the Underlying Properties.

Production and Price History

The following table summarizes our production and sales prices of oil and natural gas for the years ended December 31, 2013 and period from May 8 through December 31, 2012.

	Year Ended December 31, 2013	May 8 through December 31, 2012
Developed Properties:		
Underlying sales volumes (Boe) (a)	1,301,095	759,450
Average daily production (Boe/d)	3,565	3,549
Average price (per Boe)	$ 98.59	$ 99.23
Production cost (per Boe)	$ 32.09	$ 34.15
Remaining Properties:		
Underlying sales volumes (Boe) (b)	297,195	35,772
Average daily production (Boe/d)	814	167
Average price (per Boe)	$ 97.72	$ 96.95
Production cost (per Boe)	$ 19.12	$ 24.40

(a) Oil sales represented 97% and 97% of total sales volumes from the Developed Properties for the year ended December 31, 2013 and period from May 8, 2012 to December 31, 2012, respectively.
(b) Oil sales represented 100% of total sales volumes from the Remaining Properties.

Producing Acreage and Well Counts

All of the acreage comprising the Underlying Properties is held by production. Although many of PCEC’s wells produce both oil and associated natural gas, because the majority of production is oil-based, all of PCEC’s wells are classified as oil wells. The Underlying Properties are interests in properties located in the Santa Maria Basin and Los Angeles Basin. The following is a summary of the approximate acreage of the Underlying Properties at December 31, 2013.

	Total Acreage	
	Gross	Net
Santa Maria Basin	3,989	3,215
Los Angeles Basin	2,107	1,082
Total	6,096	4,297

The following is a summary of the producing wells on the Underlying Properties as of December 31, 2013:

	Oil		Natural Gas	
	Gross Wells(1)	Net Wells	Gross Wells(1)	Net Wells
Santa Maria Basin	227	222	—	—
Los Angeles Basin	102	62	—	—
Total	329	284	—	—

(1) Total wells include 264 wells operated by PCEC, 62 wells operated by BOLP and three wells operated by Freeport McMoRan Oil & Gas, Inc. (“FMI”).

The following is a summary of the number of development wells drilled on the Underlying Properties during 2013 and 2012.

	Year Ended December 31,			
	2013		2012	
	Gross(1)	Net	Gross(1)	Net
Development Wells:				
Productive	1	1	37	37
Dry holes	—	—	—	—
Total	1	1	37	37

(1) There were no wells in progress at December 31, 2013 and one well in progress at December 31, 2012.

Santa Maria Basin

The Santa Maria Basin consists primarily of oil reserves and prospects in multiple geologic horizons and is one of California’s largest producing oil regions. Conventional production from PCEC’s Orcutt properties is derived from the Monterey, Point Sal and SX Sand formations, which are characterized by long-lived reserves. In addition, the diatomite and Careaga formations, located at depths less than 900 feet below the surface, provide access to unconventional oil reserves. The portion of the Underlying Properties located in the Orcutt oilfield consists of 3,989 gross (3,215 net) acres.

The following table sets forth the productive zones, recovery method and certain additional information related to the Orcutt properties in the Santa Maria Basin included in the Underlying Properties:

Productive Zone	Recovery Method	Working Interest	Net Revenue Interest
Monterey / Point Sal	Waterflood	94%	89%
SX Sand	Waterflood	100%	100%
Diatomite	Cyclic steam	100%	100%
Careaga	Collection	100%	100%

Orcutt Conventional

The Orcutt oilfield was discovered in 1901 and has produced continuously since that time. Initial production from the Orcutt oilfield came from the Monterey and Point Sal formations, which are located at depths between 1,700 and 2,700 feet below the surface. The Monterey formation in the Orcutt oilfield is a fractured dolomitic shale that is highly productive. The Point Sal formation is a shallow marine deposited turbidite sandstone that is also highly productive. Oil recovery from these formations is enhanced by waterflood injection. Beginning in 2005 the SX formation underlying PCEC's Orcutt properties was developed. The SX formation is a silty sandstone at a depth of 1,300 feet below the surface. A waterflood was initiated for the SX formation in 2009 to maintain reservoir pressure. The producing wells are all artificially lifted with rod pumps and electric submersible pumps. There are currently 131 Monterey, Point Sal and SX formation producing wells, and 62 waterflood injection wells on PCEC's conventional Orcutt properties. PCEC has operated its Orcutt properties for over eight years. PCEC operates 100% of these assets and has an average working interest of approximately 96%.

Orcutt Diatomite

The diatomite is a massive silica-rich rock composed of the shells of single-cell organisms that were abundant during certain geologic periods. A diatomite formation has very high porosity (up to 70%) but very low permeability, meaning fluids will not flow through the rock. Enhanced recovery techniques are used to produce oil from a diatomite formation. In the 1990s, companies in California began to develop the heavy oil bearing diatomite formation utilizing cyclic steam injection to enable oil recovery. These diatomite formations have very high oil content but are unable to flow oil to a well bore without the cyclic steam injection. The recovery process in the diatomite consists of injecting steam into each well, letting the steam soak for one to two days, and then producing the well by flowing the hot oil and water to surface. The process is sometimes enhanced by pumping the oil and water for an additional one to four weeks, until the well is ready to be steamed again.

The diatomite formation in the Orcutt oilfield lies approximately 500 to 1,100 feet below the surface. PCEC began cyclic steam development in 2005 and was producing from about 78 active diatomite wells using the process described above as of December 31, 2013. Current production is about 1,500 Boe per day. PCEC began a project expansion in 2011 to increase the total diatomite project to 96 wells.

PCEC has targeted the diatomite formation at depths greater than 400 feet below the surface for development, the area of which covers 750 acres within PCEC's Orcutt properties. PCEC has developed approximately 50 acres to date, and produced over 1,315 MBoe from the diatomite oilfield.

Careaga formation

Overlying the diatomite formation in the Orcutt oilfield is the Careaga sandstone reservoir. The Careaga outcrops at the surface in some locations and extends to depths of 90 to 160 feet below the surface. This reservoir contains very heavy oil (11 degree API) that can flow to the surface through seeps. PCEC is collecting the Careaga oil that flows to the surface in containers utilizing a French drain system to gather the oil. PCEC is producing approximately 80 Bbls/d of the Careaga oil that is pumped from the containers and sold with the rest of its oil production.

Los Angeles Basin

The Underlying Properties in the Los Angeles Basin consist of the West Pico, Sawtelle and East Coyote properties. The portion of the Underlying Properties located in the Los Angeles Basin consists of 2,107 gross (1,082 net) acres.

The following table sets forth the recovery method and certain additional information about the oil fields in the Los Angeles Basin included in the Underlying Properties:

Field	Operator	Recovery Method	Working Interest	Net Revenue Interest
West Pico(1)	PCEC	Waterflood	95.4%	78.5%
Sawtelle	BBEP	Waterflood	37.6%	29.0 - 30.5%
East Coyote	BBEP	Waterflood	37.6%	35.2%

(1) Located in the East Beverly Hills field and includes the West Pico Unit and three Stocker JV wells (a joint venture between PCEC and FMI).

West Pico

The West Pico Unit was developed from an urban drilling and production site and came on production in 1966. In 2000, PCEC undertook a modernization of its facility and installed a permanently enclosed, electric, soundproof drilling and workover rig that allows for uninterrupted drilling and workover operations despite its close proximity to residential neighborhoods. Production from the West Pico Unit comes from sandstone reservoirs ranging in depths between 4,000 and 7,000 feet below the surface. Oil recovery is enhanced by waterflood injection. The producing wells in the West Pico Unit are all artificially lifted with rod pumps and electric submersible pumps. There are currently 37 producing wells and 6 waterflood injection wells in the West Pico Unit. Twelve new wells have been drilled from this location since 2003. PCEC has the potential to drill up to 15 additional wells in the West Pico Unit.

West Pico also includes three wells held by the Stocker JV, a joint venture between PCEC and FMI. In accordance with the contractual arrangements with FMI, FMI operates these three wells that were drilled from its facility to three lease line locations between FMI's and PCEC's production units. These wells are equally owned by PCEC and FMI, and PCEC receives the production attributable to its properties.

Sawtelle

PCEC's Sawtelle property is similarly situated in an urban environment. The Sawtelle oilfield was discovered in 1965 and is currently the deepest producing oilfield in the Los Angeles Basin with well depths up to 11,500 feet below the surface. Production at PCEC's Sawtelle property comes from sandstone reservoirs in three separate pools ranging in depth between 7,500 and 11,500 feet below the surface. Oil recovery is enhanced by waterflood injection in two of the three pools. The producing wells are all artificially lifted with hydraulic pumps, and electric submersible pumps. There are currently 11 producing wells and three waterflood injection wells in PCEC's Sawtelle property. PCEC's non-operated interest in the Sawtelle field is operated by BOLP.

East Coyote

The East Coyote oilfield was discovered in 1909. Production at PCEC's East Coyote property comes from three sandstone formations ranging in depth from 2,000 to 6,000 feet below the surface. The producing wells are all artificially lifted with rod pumps and electric submersible pumps. There are currently 51 producing wells, and 20 waterflood injection wells in PCEC's East Coyote property. PCEC's non-operated interest in the East Coyote field is operated by BOLP.

Abandonment and Sale of Underlying Properties

PCEC or any transferee has the right to abandon its interest in any well or property if it reasonably believes a well or property ceases to produce or is not capable of producing in commercially paying quantities. Upon termination of the lease, the portion of the Conveyed Interests relating to the abandoned property will be extinguished.

PCEC generally may sell all or a portion of its interests in the Underlying Properties, subject to and burdened by the Conveyed Interests, without the consent of the Trust unitholders. In connection with any such sale, PCEC will have no further obligations, requirements or responsibilities with respect to any such transferred interests, provided that PCEC delivers to the Trustee an agreement of the transferee of such transferred interests, reasonably satisfactory to the Trustee, in which such transferee assumes the responsibility to perform the Administrative Services that PCEC is required to provide to the Trust pursuant to the operating and services agreement relating to the interests being transferred. In addition, PCEC may, without the consent of the Trust unitholders, require the Trust to release the Conveyed Interests associated with any lease that accounts for less than or equal to 0.25% of the total production from the Underlying Properties in the prior twelve months and provided that the Conveyed Interests covered by such releases cannot exceed, during any twelve month period, an aggregate fair market value to the Trust of $500,000. These releases will be made only in connection with a sale by PCEC to a non-affiliate of the relevant Underlying Properties, are conditioned upon the Trust receiving an amount equal to the fair market value (net of sales costs) to the Trust of such Conveyed Interests and will be treated as an offset amount against costs and expenses. PCEC has not identified for sale any of the Underlying Properties.

Title to Properties

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

PCEC's interests in the oil and natural gas properties comprising 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 and other arrangements;
- overriding royalties, production payments and similar interests and other burdens created by PCEC’s predecessors in title;
- a variety of contractual obligations arising under operating agreements, farm-out agreements, production sales contracts and other agreements that may affect the Underlying Properties or their title;
- liens that arise in the normal course of operations, such as those for unpaid taxes, statutory liens securing unpaid suppliers and contractors and contractual liens under operating agreements that are not yet delinquent or, if delinquent, are being contested in good faith by appropriate proceedings;
- pooling, unitization and communitization agreements, declarations and orders;
- easements, restrictions, rights-of-way and other matters that commonly affect property;
- conventional rights of reassignment that obligate PCEC to reassign all or part of a property to a third party if PCEC intends to release or abandon such property;
- preferential rights to purchase or similar agreements and required third-party consents to assignments or similar agreements;
- obligations or duties affecting the Underlying Properties to any municipality or public authority with respect to any franchise, grant, license or permit, and all applicable laws, rules, regulations and orders of any governmental authority; and
- rights reserved to or vested in the appropriate governmental agency or authority to control or regulate the Underlying Properties and also the interests held therein, including PCEC’s interests and the Conveyed Interests.

PCEC has informed the Trustee that PCEC believes that the burdens and obligations affecting the properties comprising the Underlying Properties are conventional in the industry for similar properties. PCEC has also informed the Trustee that PCEC believes that the existing burdens and obligations do not, in the aggregate, materially interfere with the use of the Underlying Properties and will not materially adversely affect the Conveyed Interests or their value.

In order to give third parties notice of the Conveyed Interests, PCEC has recorded the conveyance of the Conveyed Interests in California in the real property records in each county in which the Underlying Properties are located, or in such other public records as required under California law to place third parties on notice of the conveyance.

PCEC believes that its title to the Underlying Properties is, and the Trust’s title to the Conveyed Interests are, good and defensible in accordance with standards generally accepted in the oil and gas industry, subject to such exceptions as are not so material to detract substantially from the use or value of such properties or royalty interests. Under the terms of the Conveyance creating the Conveyed Interests, PCEC has provided a special warranty of title with respect to the Conveyed Interests, subject to the burdens and obligations described in this section. Please read “Risk Factors—The Trust Units may lose value as a result of title deficiencies with respect to the Underlying Properties.”

Item 3. Legal Proceedings.

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

Item 4. Mine Safety Disclosures.

Not applicable.

PART II

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

The Trust Units commenced trading on the New York Stock Exchange on May 3, 2012 under the symbol "ROYT." Prior to May 3, 2012, there was no established public trading market for the Trust Units. The high and low sales prices per unit for each quarter of 2013 and from May 3, 2012 through December 31, 2012 were as follows:

2013	Price Range High	Price Range Low	Distributions Paid
First Quarter (January 1 through March 31)	$ 18.97	$ 17.34	$ 0.44460
Second Quarter (April 1 through June 30)	$ 18.75	$ 17.61	$ 0.43525
Third Quarter (July 1 through September 30)	$ 18.36	$ 15.86	$ 0.48173
Fourth Quarter (October 1 through December 31)	$ 16.09	$ 12.52	$ 0.43601

May 3, 2012 through December 31, 2012	Price Range High	Price Range Low	Distributions Paid
May 3, 2012 through June 30, 2012	$ 20.35	$ 15.75	$ 0.16234
Third Quarter (July 1 through September 30)	$ 19.10	$ 17.87	$ 0.45429
Fourth Quarter (October 1 through December 31)	$ 18.80	$ 16.21	$ 0.44154

At December 31, 2013, there were 38,583,158 Trust Units outstanding. On March 14, 2014 the closing sales price of the Trust Units as reported by the NYSE was $13.13 per unit, and there were six unitholders of record. This number does not include owners for whom Trust Units may be held in "street" name.

Distributions

Each month, the Trustee determines the amount of funds available for distribution to the Trust unitholders. Available funds are the excess cash, if any, received by the Trust from the Conveyed Interests and other sources (such as interest earned on any amounts reserved by the Trustee) that month, over the Trust's liabilities for that month, subject to adjustments for changes made by the Trustee during the month in any cash reserves established for future liabilities of the Trust. Distributions are made to the holders of Trust Units as of the applicable record date (generally within five business days after the last business day of each calendar month) and are payable on or before the 10th business day after the record date. The following table illustrates information regarding the Trust's distributions paid during the year ended December 31, 2013 and for the period from May 8, 2012 through December 31, 2012.

Year Ended December 31, 2013

Declaration Date	Record Date	Payment Date	Distribution per Unit
December 21, 2012	December 31, 2012	January 15, 2013	$ 0.13941
January 25, 2013	February 4, 2013	February 14, 2013	$ 0.15116
February 25, 2013	March 7, 2013	March 14, 2013	$ 0.15403
March 26, 2013	April 5, 2013	April 15, 2013	$ 0.13655
April 22, 2013	May 2, 2013	May 14, 2013	$ 0.14600
May 24, 2013	June 3, 2013	June 14, 2013	$ 0.15270
June 25, 2013	July 5, 2013	July 15, 2013	$ 0.15721
July 26, 2013	August 5, 2013	August 14, 2013	$ 0.15462
August 27, 2013	September 6, 2013	September 16, 2013	$ 0.16990
September 24, 2013	October 4, 2013	October 14, 2013	$ 0.15761
October 24 , 2013	November 7, 2013	November 14, 2013	$ 0.14756
November 25, 2013	December 5, 2013	December 13, 2013	$ 0.13084

Period from May 8 to December 31, 2012

Declaration Date	Record Date	Payment Date		Distribution per Unit
May 21, 2012	May 31, 2012	June 15, 2012	$	0.16234
June 19, 2012	June 29, 2012	July 16, 2012	$	0.15392
July 20, 2012	July 31, 2012	August 14, 2012	$	0.15187
August 21, 2012	August 31, 2012	September 14, 2012	$	0.14850
September 18, 2012	September 28, 2012	October 12, 2012	$	0.14987
October 19, 2012	October 31, 2012	November 14, 2012	$	0.13939
November 20, 2012	November 30, 2012	December 14, 2012	$	0.15228

Equity Compensation Plans

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

Sales of Unregistered Securities and Use of Proceeds

There were no sales of unregistered securities during the period covered by this report.

Purchases of Equity Securities

There were no purchases of Trust Units by the Trust or any affiliated purchaser during the fourth quarter of 2013.

Item 6. Selected Financial Data.

The Trust was formed in January 2012. The Conveyance of the NPI and the Overriding Royalty Interest, however, did not occur until May 8, 2012. As a result, the Trust did not recognize any income or make any distributions during the first quarter of 2012.

The following table sets forth selected data for the Trust for the year ended December 31, 2013 and for the period from May 8, 2012 through December 31, 2012 and as of December 31, 2013 and 2012.

Thousands of dollars, except per unit amounts		Year ended December 31, 2013		May 8, 2012 through December 31, 2012
Income from conveyed interests	$	70,082	$	41,319
Distributable income	$	69,356	$	40,828
Distributable income per unit	$	1.79759	$	1.05817
Trust corpus (38,583,158 units)	$	250,872	$	271,209

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

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

Overview

The Trust is a statutory trust formed in January 2012 under the Delaware Statutory Trust Act. The business and affairs of the Trust are administered by The Bank of New York Mellon Trust Company, N.A. (the "Trustee"). The Trust's purpose is to hold the Conveyed Interests (described below), to distribute to the Trust unitholders cash that the Trust receives in respect of the Conveyed Interests, subject to the effects of the commodity derivative contracts described below under "Commodity Derivative Contracts," and to perform certain administrative functions in respect of the Conveyed Interests and the Trust Units. The Trust does not conduct any operations or activities. The Trustee has no authority over or responsibility for, and no involvement with, any aspect of the oil and gas operations or other activities on the Underlying Properties. Wilmington Trust, National Association, as the Delaware Trustee (the "Delaware Trustee"), has only minimal rights and duties as are necessary to satisfy the requirements of the Delaware Statutory Trust Act. The Trust derives all or substantially all of its income and cash flow from the Conveyed Interests, subject to the effects of the commodity derivative contracts. The Trust is treated as a grantor trust for U.S. federal income tax purposes.

The Trust was created to acquire and hold net profits and royalty interests in certain oil and natural gas properties located in California and further described below for the benefit of the Trust unitholders pursuant to an agreement among Pacific Coast Energy Company, LP, a privately held Delaware limited partnership ("PCEC"), the Trustee and the Delaware Trustee. The Conveyed Interests (as defined below) represent undivided interests in underlying properties consisting of PCEC's interests in its oil and natural gas properties located onshore in California (the "Underlying Properties"). The Conveyed Interests were conveyed by PCEC to the Trust concurrent with the initial public offering of the Trust's common units in May 2012.

Concurrent with the initial public offering, on May 8, 2012, the Trust and PCEC entered into a Conveyance of Net Profits Interest and Overriding Royalty Interest (the "Conveyance"), pursuant to which PCEC conveyed to the Trust net profits interest and an overriding royalty interest (the "Conveyed Interests") in the Underlying Properties. The Conveyed Interests entitle the Trust to receive 80% of the net profits from the sale of oil and natural gas production from the proved developed reserves as of December 31, 2011 on the Underlying Properties (the "Developed Properties") and either 25% of the net profits from the sale of oil and natural gas production from all other development potential on the Underlying Properties (the "Remaining Properties") or a 7.5% royalty interest from the sale of oil and natural gas production from the Remaining Properties located in PCEC's Orcutt properties (the "Royalty Interest Proceeds").

On September 19, 2013, the Trust, PCEC and the Other Selling Unitholders entered into the Underwriting Agreement with the Underwriters, with respect to the Offering by PCEC and the Other Selling Unitholders. On September 23, 2013, PCEC distributed 11,216,661 Trust Units to the Other Selling Unitholders. Immediately following the distribution on September 23, 2013, the Other Selling Unitholders sold 8,500,000 Trust Units, and PCEC sold an additional 5,000,000 Trust Units, for a total sale of 13,500,000 Trust Units. PCEC retained 3,866,497 Trust Units, or 10% of the issued and outstanding Trust Units. The Trust received no proceeds from the sales of these Trust Units.

The Trust calculates the net profits and royalties for the Developed Properties and Remaining Properties monthly. For any monthly period during which costs for the Remaining Properties exceed gross proceeds, the Trust is entitled to receive the Royalty Interest Proceeds, and the Trust continues to receive such proceeds until the first day of the month following the day on which cumulative gross proceeds for the Remaining Properties exceed the cumulative total excess costs for the Remaining Properties (such occurrence being herein called an "NPI Payout"). Due to significant planned capital expenditures associated with the Remaining Properties for the benefit of the Trust, PCEC expects the Trust to receive payments associated with the Remaining Properties in the form of Royalty Interest Proceeds until the NPI Payout occurs in approximately 2021. In any monthly period following an NPI Payout, the Trust is entitled to receive Royalty Interest Proceeds if costs for the Remaining Properties exceed gross proceeds.

The Trust makes monthly cash distributions of all of its monthly cash receipts, after deduction of fees and expenses for the administration of the Trust, to holders of its Trust Units as of the applicable record date (generally within five business days after the last business day of each calendar month) on or before the 10th business day after the record date. Actual cash distributions to the Trust unitholders fluctuates monthly based upon the quantity of oil and natural gas produced from the Underlying Properties, the prices received for oil and natural gas production, costs to develop and produce the oil and natural gas and other factors. Because payments to the Trust are generated by depleting assets with the production from the Underlying Properties diminishing over time, a portion of each distribution represents, in effect, a return of a unitholder's original investment. Oil and natural gas production from proved reserves attributable to the Underlying Properties will decline over time.

Properties

The Underlying Properties consist of the Developed Properties and the Remaining Properties. Production from the Developed Properties attributable to the Trust is produced from wells that, because they have already been drilled, require limited additional capital expenditures. Production from the Remaining Properties attributable to the Trust requires capital expenditures for the drilling of wells and installation of infrastructure. PCEC is providing required capital on behalf of the Trust during this period; however, because the costs initially incurred exceed gross proceeds, the Remaining Properties have negative net profits during the drilling and development period. During this period of negative net profits, instead of being paid net profits, the Trust is being paid a 7.5% overriding royalty on the portion of the Remaining Properties located on PCEC's Orcutt properties. Once revenues from the Remaining Properties have paid back PCEC for the cumulative costs it has advanced on behalf of the Trust, the NPI on the Remaining Properties will be paid out in place of the royalty interests, as described below. The royalty interest conveyed to the Trust is referred to herein as the "Royalty Interest". These interests, collectively the "Conveyed Interests," entitle the Trust to receive the following:

Developed Properties

- 80% of the net profits from the sale of oil and natural gas production from the Developed Properties.

Remaining Properties

- 7.5% of the proceeds (free of any production or development costs but bearing the proportionate share of production and property taxes and post-production costs) attributable to the sale of all oil and natural gas production from the Remaining Properties located on PCEC's Orcutt properties, including but not limited to PCEC's interest in such production (the "Royalty Interest Proceeds"), or

- 25% of the net profits from the sale of oil and natural gas production from all of the Remaining Properties.

The Trust calculates the net profits and royalties for the Developed Properties and the Remaining Properties separately. Any excess costs for either the Developed Properties or the Remaining Properties does not reduce net profits calculated for the other. The amount of Royalty Interest Proceeds paid is taken into account in the net profits interest calculation for the Remaining Properties. If at any time cumulative costs for the Developed Properties or the Remaining Properties exceed cumulative gross proceeds associated with such properties, neither the Trust nor the Trust unitholders are liable for the excess costs, but the Trust does not receive any net profits from the Developed Properties or the Remaining Properties, as the case may be, until future cumulative net profits for such properties exceed the cumulative total excess costs for such properties.

The Trust is not subject to any pre-set termination provisions based on a maximum volume of oil or natural gas to be produced or the passage of time. The Trust will dissolve upon the earliest to occur of the following: (1) the Trust, upon approval of the holders of at least 75% of the outstanding Trust Units, sells the Net Profits Interest, (2) the annual cash received by the Trust attributable to the Conveyed Interests, in the aggregate, is less than $2.0 million for each of any two consecutive years, (3) the holders of at least 75% of the outstanding Trust Units vote in favor of dissolution or (4) the Trust is judicially dissolved.

Commodity Derivative Contracts

The revenues derived from the Underlying Properties depend substantially on prevailing oil prices and, to a lesser extent, natural gas prices. As a result, commodity prices also affect the amount of cash flow available for distribution to the Trust unitholders. Lower prices may also reduce the amount of oil and natural gas that PCEC or the third-party operators can economically produce. PCEC entered into commodity derivative contracts to reduce the exposure of the revenues from oil production from the Underlying Properties to fluctuations in oil prices and to achieve more predictable cash flow. However, these contracts limit the amount of cash available for distribution if prices increase above the fixed hedge price. None of the Trust's exposure to natural gas prices is hedged.

PCEC entered into commodity derivative contracts with Wells Fargo Bank, National Association in order to mitigate the effects of falling commodity prices through March 31, 2014. The Trust is entitled to the effect of 2,000 barrels of daily swap volumes of ICE Brent crude oil at $115.00 per barrel during the twenty-four months ending March 31, 2014, proportional to the Trust's interest in the Developed Properties.

The amounts received by PCEC from the commodity derivative contract counterparty upon settlement of the commodity derivative contracts reduce the operating expenses related to the Underlying Properties in calculating net profits. In addition, the aggregate amounts paid by PCEC upon settlement of the commodity derivative contracts related to the Underlying Properties reduce the amount of net profits paid to the Trust.

For the year ended December 31, 2013, the Trust received net settlements from the commodity derivative contracts related to the Underlying Properties of approximately $4.6 million, which was approximately 6.6% of the total amount of cash the Trust received from PCEC in 2013. As the commodity derivative contracts expire as to production after March 31, 2014, the Trust will no longer have the benefit of the commodity derivative contracts. The Trust's future cash receipts should therefore be expected to be more volatile, and may well be lower, than they would have been if the commodity derivative contracts were of longer duration.

Results of Operations

For the year ended December 31, 2013 and the period from May 8, 2012 through December 31, 2012, income from NPI received by the Trust amounted to $70.1 million and $41.3 million, respectively. The NPI received by the Trust for the year ended December 31, 2013 was primarily associated with the net profits for oil and natural gas production during the months of November and December 2012 and January through October 2013. The net profits income received by the Trust during 2012 was primarily associated with net profits for oil and natural gas production during the months of April through October 2012.

The following table displays PCEC's underlying sales volumes and average prices for the Underlying Properties, representing the amounts included in the net profits calculation for distributions paid during the year ended December 31, 2013 and from May 8, 2012 to December 31, 2012.

	Year Ended December 31, 2013	May 8 through December 31, 2012
Developed Properties:		
Underlying sales volumes (Boe) (a)	1,301,095	759,450
Average daily production (Boe/d)	3,655	3,204
Average price (per Boe)	$ 98.59	$ 99.23
Production cost (per Boe)	$ 32.09	$ 34.15
Remaining Properties:		
Underlying sales volumes (Boe) (b)	297,195	35,772
Average daily production (Boe/d)	814	151
Average price (per Boe)	$ 97.72	$ 96.95
Production cost (per Boe)	$ 19.12	$ 24.40

(a) Oil sales represented 97% of total sales volumes from the Developed Properties for the year ended December 31, 2013 and the period from May 8, 2012 to December 31, 2012.

(b) Oil sales represented 100% of total sales volumes from the Remaining Properties.

Computation of Net Profits Income Received by the Trust

The Trust's net profits and royalty income consist of monthly net profits and royalty income attributable to the Conveyed Interests. Net profits and royalty income for the year ended December 31, 2013 and for the period from May 8, 2012 to December 31, 2012 was determined as shown in the following table. The Trust did not receive any income for the three months ended March 31, 2012.

Thousands of dollars	Year Ended December 31, 2013	May 8 through December 31, 2012
Developed Properties—80% Net Profits Interest		
Gross profits:		
Oil sales	$ 127,230	$ 74,960
Natural gas sales	1,048	403
Total	128,278	75,363
Costs:		
Direct operating expenses:		
Lease operating expenses	38,099	23,474
Production and other taxes	3,655	2,464
Development expenses	6,064	327
Total	47,818	26,265
Total income	80,460	49,098
Net Profits Interest	80%	80%
Income from Net Profits Interest	$ 64,368	$ 39,279
Remaining Properties—25% Net Profits Interest		
Total Revenues:		
Oil sales	$ 29,043	$ 3,468
Total	29,043	3,468
7.5% Overriding Royalty Interest	2,125	260
Costs:		
Direct operating expenses:		
Lease operating expenses	4,975	873
Production and other taxes	708	—
Development expenses	14,706	23,226
Total	20,389	24,099
Total income (excess cost)	6,529	(20,891)
Net Profits Interest	25%	25%
25% Net Profits Interest Income (Deficit)(1)	$ 1,632	$ (5,223)
Total Trust Cash Flow		
80% Net Profit Interest	$ 64,368	$ 39,279
7.5% Overriding Royalty Interest	2,125	260
Settlement of commodity derivative contracts	4,601	2,364
PCEC operating and service fee	(1,012)	(583)
Total	$ 70,082	$ 41,320
Trust general and administrative expenses and cash withheld for expenses	(726)	(492)
Distributable income	$ 69,356	$ 40,828

(1) 25% Net Profits Interest Accrued Deficit	Twelve Months Ended December 31, 2013	May 8 through December 31, 2012
Beginning balance	$ (5,223)	$ —
Current period	1,632	(5,223)
Ending balance	$ (3,591)	$ (5,223)

Year ended December 31, 2013 and period from May 8 to December 31, 2012

Income from the Developed Properties, before net settlements related to commodity derivative contracts, was approximately $64.4 million in 2013 compared to $39.3 million in 2012, reflecting a shorter period of operation during 2012. The increase in the excess revenue is attributed principally to the different period of operation, resulting in higher production compared to the previous period in 2012, partially offset by higher capital expenditures. Included in the net profits calculation were approximately $6.1 million and $38.1 million of capital expenditures and lease operating expenses, respectively. During 2012, approximately $0.3 million and $23.5 million of capital expenditures and lease operating expenses, respectively, were included in the net profits calculation.

For the Remaining Properties, NPI income was $1.6 million for the year ended December 31, 2013, compared to a deficit of $5.2 million for the period from May 8 through December 31, 2012. Since a cumulative deficit existed on the 25% net profits interest, the Trust received approximately $2.1 million in 2013 from the 7.5% Overriding Royalty attributable to the sale of all production from the Remaining Properties located on PCEC's Orcutt Properties. Costs exceeded gross proceeds by $20.9 million for 2012, therefore the Trust received $0.3 million from the 7.5% Overriding Royalty attributable to the sale of all production from the Remaining Properties located on PCEC's Orcutt Properties. The cumulative deficit of the net profits interest on the Remaining Properties, including the 7.5% Overriding Royalty, was approximately $3.6 million at December 31, 2013.

Net settlement receipts related to the commodity derivative contracts were $4.6 million for 2013 compared to $2.4 million for 2012.

PCEC charged the Trust $1.0 million and $0.6 million for the Operating and Service Fee during 2013 and 2012, respectively. The annual amount of the Operating and Service Fee was $1.0 million from April 1, 2012 through March 31, 2013. Commencing April 1, 2013, the Operating and Services Fee increased 2% to $1,021,000 based on changes to the CPI. The fee will adjust annually each April 1.

The total cash received by the Trust from PCEC in 2013 was approximately $70.1 million compared to approximately $41.3 million in 2012. The Trustee paid general and administrative expenses of $0.7 million during 2013 compared with $0.5 million during 2012. Expenses paid for the year ended December 31, 2013 and prior period ended December 31, 2012 consisted primarily of Trustee fees, accounting, tax and legal fees and New York Stock Exchange listing fees. Distributable income was approximately $69.4 million and $40.8 million, respectively, for 2013 and 2012.

Liquidity and Capital Resources

Other than Trust administrative expenses, including any reserves established by the Trustee for future liabilities, the Trust's only use of cash is for distributions to Trust unitholders. Available funds are the excess cash, if any, received by the Trust from the Conveyed Interests and other sources (such as interest earned on any amounts reserved by the Trustee) in that month, over the Trust's expenses paid for that month. Available funds are reduced by any cash the Trustee determines to hold as a reserve against future expenses.

The Trustee may create a cash reserve to pay for future liabilities of the Trust. If the Trustee determines that the cash on hand and the cash to be received are, or will be, insufficient to cover the Trust's liabilities, the Trustee may cause the Trust to borrow funds to pay liabilities of the Trust. The Trustee may also cause the Trust to mortgage its assets to secure payment of the indebtedness. If the Trustee causes the Trust to borrow funds, the Trust unitholders will not receive distributions until the borrowed funds are repaid. As of December 31, 2013 the Trust had cash on hand of $39,005 for future Trust expenses.

The Trust calculates net profits and royalties from the Underlying Properties separately for each of the Developed Properties and the Remaining Properties. Any excess costs for either the Developed Properties or the Remaining Properties do not reduce net profits calculated for the other. Similarly, the cash on hand for either the Developed Properties or the Remaining Properties is not applied to cover the costs of the other.

Each month, the Trustee pays Trust obligations and expenses and distribute to the Trust unitholders the remaining proceeds received from the Conveyed Interests. The cash held by the Trustee as a reserve against future liabilities or for distribution at the next distribution date may be invested in a limited number of permitted investments. Alternatively, cash held for distribution at the next distribution date may be held in a noninterest bearing account.

PCEC has provided the Trust with a $1.0 million letter of credit to be used by the Trust in the event that its cash on hand (including available cash reserves) is not sufficient to pay ordinary course administrative expenses as they become due.

Further, if the Trust requires more than the $1.0 million under the letter of credit to pay administrative expenses, PCEC has agreed to loan funds to the Trust necessary to pay such expenses. Any funds provided under the letter of credit or loaned by PCEC may only be used for the payment of current accounts or other obligations to trade creditors in connection with obtaining goods or services or for the payment of other accrued current liabilities arising in the ordinary course of the Trust's business, and may not be used to satisfy Trust indebtedness. If the Trust draws on the letter of credit or PCEC loans funds to the Trust, no further distributions will be made to Trust unitholders (except in respect of any previously determined monthly cash distribution amount) until such amounts drawn or borrowed, including interest thereon, are repaid. Any loan made by PCEC 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 PCEC and an unaffiliated third party.

The Trustee has no current plans to authorize the Trust to borrow money. During 2013, there were no borrowings and no draws on the letter of credit.

Distributions Paid and Declared After Year End

On January 15, 2014 the distribution of $0.12833 per Trust Unit, which was declared on December 23, 2013 was paid to Trust unitholders owning Trust Units as of January 6, 2014.

Subsequent to December 31, 2013, the Trust declared the following distributions:

Declaration Date	Record Date	Payment Date	Distribution per Unit
January 23, 2014	February 5, 2014	February 14, 2014	$ 0.13396
February 25, 2014	March 6, 2014	March 14, 2014	$ 0.12574

Off-Balance Sheet Arrangements

The Trust has no off-balance sheet arrangements and does not have any transactions, arrangements or other relationships with unconsolidated entities or persons that could materially affect the Trust's liquidity or the availability of capital resources.

Contractual Obligations

A summary of the Trust's contractual obligations as of December 31, 2013 is provided in the following table (in thousands):

	Payments Due by Year						
Thousands of dollars	2014	2015	2016	2017	2018	After 2018	Total
PCEC Operating and Services fee	$ 1,032	$ 1,036	$ 1,036	$ 1,036	$ 1,036	(a)	(a)
Trustee Administrative fee	200	200	200	200	200	(b)	(b)
Delaware Trustee fee	2	2	2	2	2	(b)	(b)
Total	$ 1,234	$ 1,238	$ 1,238	$ 1,238	$ 1,238		

(a) Under the terms of the Operating and Services Fee Agreement, the Trust pays a monthly operational and services fee to PCEC. The fee will change annually each April 1 based on changes to the Consumer Price Index.

(b) Under the terms of the Trust Agreement, the Trust pays an annual administrative fee of $200,000 to the Trustee and $2,000 to the Delaware Trustee. Because the term of the NPI and the Trust are not limited, the aggregate amounts of future payments cannot be calculated.

Accounting Pronouncements

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

Critical Accounting Policies and Estimates

The Trust uses the modified cash basis of accounting to report Trust receipts of the Conveyed Interests and payments of expenses incurred. The NPI represent the right to receive revenues (oil and natural gas sales), less direct operating expenses (lease operating expenses and production and property taxes) and development expenses of the Underlying Properties plus certain offsets. The Royalty Interest represents the right to receive revenues (oil and natural gas sales), less production and operating taxes and post-production costs. Cash distributions of the Trust are made based on the amount of cash received by the Trust pursuant to terms of the Conveyance creating the Conveyed Interests.

The financial statements of the Trust, as prepared on a modified cash basis, reflect the Trust's assets, liabilities, Trust corpus, earnings and distributions as follows:

- Income from the Conveyed Interests is recorded when distributions are received by the Trust;
- Distributions to Trust unitholders are recorded when paid by the Trust;
- Trust general and administrative expenses (which include the Trustee's fees as well as accounting, engineering, legal, and other professional fees) are recorded when paid;
- PCEC's operating and services fee is recorded when paid; and
- Cash reserves for Trust expenses may be established by the Trustee for certain expenditures that would not be recorded as contingent liabilities under US GAAP.

The initial carrying value of the NPI was PCEC's historical net book value of the interests on May 8, 2012, the date of transfer to the Trust, except for the commodity derivatives which were reflected at their fair value as of May 8, 2012.

Amortization of the investment in the Conveyed Interests is calculated on a unit-of-production basis and is charged directly to Trust corpus. Such amortization does not affect cash earnings of the Trust.

Investment in the Conveyed Interests is periodically assessed to determine whether its aggregate value has been impaired below its total capitalized cost based on the Underlying Properties. If an impairment loss is indicated by the carrying amount of the assets exceeding the sum of the undiscounted expected future net cash flows, then an impairment loss is recognized for the amount by which the carrying amount of the asset exceeds its estimated fair value. Fair value is generally determined from estimated discounted cash flows.

While these statements differ from financial statements prepared in accordance with US GAAP, the modified cash basis of reporting revenues, expenses, and distributions is considered to be the most meaningful because monthly distributions to the Trust unitholders are based on net cash receipts. This comprehensive basis of accounting other than US GAAP corresponds to the accounting permitted for royalty trusts by the U.S. Securities and Exchange Commission as specified by Staff Accounting Bulletin Topic 12:E, Financial Statements of Royalty Trusts.

The Conveyed Interests were conveyed by PCEC to the Trust on May 8, 2012. During the three months ended March 31, 2012, no payments from the Conveyed Interests were received, no Trust general and administrative expenses were paid and no operating and services fees to PCEC were incurred.

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

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

Commodity Price Risk. The Trust's most significant market risk relates to the prices received for oil and natural gas production. The revenues derived from the Underlying Properties depend substantially on prevailing oil prices and, to a lesser extent, natural gas prices. As a result, commodity prices also affect the amount of cash flow available for distribution to the Trust unitholders. Lower prices may also reduce the amount of oil and natural gas that PCEC or the third-party operators can economically produce.

Credit Risk. The Trust's most significant credit risk is the risk of the bankruptcy of PCEC. The bankruptcy of PCEC could impede the operation of wells and the development of the proved undeveloped reserves. Further, in the event of the bankruptcy of PCEC, if a court held that the Net Profits Interests were part of the bankruptcy estate, the Trust might be treated as an unsecured creditor with respect to the NPI. In addition, PCEC has entered into commodity derivative contracts to reduce the exposure of the revenues from oil production from the Underlying Properties to fluctuations in oil prices and to achieve more predictable cash flow. These contracts also limit the amount of cash available for distribution if prices increase above the fixed hedge price. The use of these contracts involves the risk that the counterparty will be unable to meet its obligations under the contracts. The commodity derivative contracts are with Wells Fargo Bank, National Association. All payments from the commodity derivative contract counterparty are paid to PCEC.

In 2013, Phillips 66 accounted for 94% of PCEC's net sales. Phillips 66's purchase of production from the Orcutt properties is pursuant to a long-term sales contract between Phillips 66 and PCEC, and its purchase of production from West Pico properties is pursuant to a month-to-month sales contract.

Item 8. Financial Statements and Supplementary Data.

Report of Independent Registered Public Accounting Firm

To the Unitholders of Pacific Coast Oil Trust and to The
Bank of New York Mellon Trust Company, N.A., Trustee

We have audited the accompanying statements of assets and trust corpus of Pacific Coast Oil Trust as of December 31, 2013 and 2012, and the related statements of distributable income and changes in trust corpus for the year ended December 31, 2013 and the period from May 8, 2012 (date of inception) through December 31, 2012. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the assets and trust corpus of the Trust at December 31, 2013 and 2012, and the distributable income and changes in trust corpus for the year ended December 31, 2013 and the period from May 8, 2012 (date of inception) through December 31, 2012, on the basis of accounting described in Note 2.

/s/ PricewaterhouseCoopers LLP
Los Angeles, California
March 17, 2013

PACIFIC COAST OIL TRUST

Statements of Assets and Trust Corpus

Thousands of dollars	December 31, 2013	December 31, 2012
ASSETS		
Cash and cash equivalents	$ 39	$ 17
Investment in conveyed interests, net of amortization (Note 2)	250,833	271,192
Total assets	$ 250,872	$ 271,209
TRUST CORPUS		
Trust corpus (38,583,158 Trust Units issued and outstanding)	$ 250,872	$ 271,209
Total Trust corpus	$ 250,872	$ 271,209

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

PACIFIC COAST OIL TRUST

Statements of Distributable Income

Thousands of dollars, except per unit amounts	Year Ended December 31, 2013	May 8 to December 31, 2012
Income from conveyed interests	$ 70,082	$ 41,319
General and administrative expenses	(704)	(474)
Cash reserves withheld for Trust expenses	(22)	(17)
Distributable income	$ 69,356	$ 40,828
Distributable income per unit (38,583,158 units)	$ 1.79759	$ 1.05817

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

PACIFIC COAST OIL TRUST

Statements of Changes in Trust Corpus

Thousands of dollars	Year Ended December 31, 2013	May 8 to December 31, 2012
Trust corpus, beginning of period	$ 271,209	$ 1
Investment in conveyed interests	—	284,493
Cash reserves (used) withheld for future Trust expenses	22	17
Distributable income	69,356	40,828
Distributions to unitholders	(69,356)	(40,828)
Amortization of conveyed interests	(20,359)	(13,302)
Trust corpus, end of period	$ 250,872	$ 271,209

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

PACIFIC COAST OIL TRUST

NOTES TO FINANCIAL STATEMENTS

1. ORGANIZATION OF THE TRUST

Formation of the Trust

Pacific Coast Oil Trust (the "Trust") is a Delaware statutory Trust formed in January 2012 under the Delaware Statutory Trust Act pursuant to a Trust Agreement among Pacific Coast Energy Company LP ("PCEC"), as trustor, The Bank of New York Mellon Trust Company, N.A., as Trustee (the "Trustee"), and Wilmington Trust, National Association, as Delaware Trustee (the "Delaware Trustee"). The initial contribution to the Trust was $10. The Trust Agreement was amended and restated by PCEC, the Trustee and the Delaware Trustee on inception date (May 8, 2012). References in this report to the "Trust Agreement" are to the amended and restated Trust agreement.

The Trust was created to acquire and hold net profits and royalty interests in certain oil and natural gas properties located in California (the "Conveyed Interests") for the benefit of the Trust unitholders pursuant to an agreement among PCEC, the Trustee and the Delaware Trustee. The Conveyed Interests represent undivided interests in underlying properties consisting of PCEC's interests in its oil and natural gas properties located onshore in California (the "Underlying Properties"). The Conveyed Interests were conveyed by PCEC to the Trust concurrent with the initial public offering of the Trust's common units in May 2012.

The Conveyed Interests are passive in nature and neither the Trust nor the Trustee has any control over, or responsibility for, costs relating to the operation of the Underlying Properties. The Conveyed Interests entitle the Trust to receive 80% of the net profits from the sale of oil and natural gas production from proved developed reserves on the Underlying Properties as of December 31, 2011 and either a 25% net profits interest from the sale of oil and natural gas production from all other development potential on the Underlying Properties (the "Remaining Properties") or a 7.5% royalty interest from the sale of oil and natural gas production from the Remaining Properties located in PCEC's Orcutt properties (the "Royalty Interest Proceeds").

The Trust calculates the net profits and royalties for the Developed Properties and Remaining Properties monthly. For any monthly period during which costs for the Remaining Properties exceed gross proceeds, the Trust is entitled to receive the Royalty Interest Proceeds, and the Trust continues to receive such proceeds until the first day of the month following the day on which cumulative gross proceeds for the Remaining Properties exceed the cumulative total excess costs for the Remaining Properties (herein referred to as an "NPI Payout"). Due to significant planned capital expenditures associated with the Remaining Properties for the benefit of the Trust, PCEC expects the Trust to receive payments associated with the Remaining Properties in the form of Royalty Interest Proceeds until the NPI Payout occurs in approximately 2021. In any monthly period following an NPI Payout, the Trust is entitled to receive Royalty Interest Proceeds if costs for the Remaining Properties exceed gross proceeds.

The Trustee can authorize the Trust to borrow money to pay Trust administrative or incidental expenses that exceed cash held by the Trust. The Trustee may authorize the Trust to borrow from the Trustee as a lender provided the terms of the loan are fair to the Trust unitholders and similar to the terms it would grant to a similarly situated commercial customer with whom it did not have a fiduciary relationship. The Trustee may also deposit funds awaiting distribution in an account with itself, if the interest paid to the Trust at least equals amounts paid by the Trustee on similar deposits, and make other short-term investments with the funds distributed to the Trust.

Conveyance of Net Profits Interest and Overriding Royalty Interest and Public Offerings

On May 8, 2012, the Trust and PCEC entered into a Conveyance of NPI and Overriding Royalty Interest (the "Conveyance"), pursuant to which PCEC conveyed to the Trust the Net Profits Interest and the Royalty Interest, which are collectively referred to herein as the "Conveyed Interests".

Concurrent with the Conveyance, PCEC sold 18,500,000 Trust Units to the public in an initial public offering ("IPO"). The proceeds (net of underwriting discounts of approximately $23 million) received by PCEC (before expenses) from the sale of 18,500,000 Trust Units were approximately $346.9 million. The Trust received no proceeds from the sale of the Trust Units. The IPO is described in the final Prospectus filed with the Securities and Exchange Commission pursuant to Rule 424(b)(1) on May 4, 2012 (the "Prospectus"). Upon completion of the offering, there were 38,583,158 Trust Units issued and outstanding, of which PCEC owned 20,083,158 Trust Units, or 52% of the issued and outstanding Trust Units.

On September 19, 2013, the Trust, PCEC and other persons or entities (, the "Other Selling Unitholders") sold 13,500,000 Trust Units at a price of $17.10 per Trust unit ($16.416 per Trust unit, net of underwriting discounts and commissions). On September 23, 2013, PCEC distributed 11,216,661 Trust Units to the Other Selling Unitholders. Immediately following the distribution, the Other Selling Unitholders sold 8,500,000 Trust Units, and PCEC sold an additional 5,000,000 Trust Units, for a total sale of 13,500,000 Trust Units. PCEC retained 3,866,497 Trust Units, or 10% of the issued and outstanding Trust Units. The Trust received no proceeds from the sales of these Trust Units.

Note 2. Trust Significant Accounting Policies

Basis of Accounting

The Trust uses the modified cash basis of accounting to report Trust receipts of the Conveyed Interests and payments of expenses incurred. The NPI represent the right to receive revenues (oil and natural gas sales), less direct operating expenses (lease operating expenses and production and property taxes) and development expenses of the Underlying Properties plus certain offsets. The Royalty Interest represents the right to receive revenues (oil and natural gas sales), less production and operating taxes and post-production costs. Cash distributions of the Trust are made based on the amount of cash received by the Trust pursuant to terms of the Conveyance creating the Conveyed Interests.

The financial statements of the Trust, as prepared on a modified cash basis, reflect the Trust's assets, liabilities, Trust corpus, earnings and distributions as follows:

- Income from the Conveyed Interests is recorded when distributions are received by the Trust;
- Distributions to Trust unitholders are recorded when paid by the Trust;
- Trust general and administrative expenses (which include the Trustee's fees as well as accounting, engineering, legal, and other professional fees) are recorded when paid;
- PCEC's operating and services fee is recorded when paid; and
- Cash reserves for Trust expenses may be established by the Trustee for certain expenditures that would not be recorded as contingent liabilities under US GAAP.

The Conveyance of the Conveyed Interests to the Trust was accounted for as a transfer of properties under common control and recorded at PCEC's historical net book value of the Conveyed Interests on May 8, 2012, the date of transfer to the Trust, except for the commodity derivatives which were reflected at their fair value as of May 8, 2012.

Amortization of the investment in the Conveyed Interests is calculated on a unit-of-production basis and is charged directly to the Trust corpus. During the year ended December 31, 2013 and for the period from May 8, 2012 through December 31, 2012, amortization expense was $20.4 million and $13.3 million, respectively. Such amortization does not affect cash earnings of the Trust. Accumulated amortization as of December 31, 2013 and 2012 was $33.7 million and $13.3 million, respectively.

Investment in the Conveyed Interests is periodically assessed to determine whether its aggregate value has been impaired below its total capitalized cost based on the Underlying Properties. If an impairment loss is indicated by the carrying amount of the assets exceeding the sum of the undiscounted expected future net cash flows, then an impairment loss is recognized for the amount by which the carrying amount of the asset exceeds its estimated fair value. Fair value is generally determined from estimated discounted cash flows. There was no impairment as of December 31, 2013 or December 31, 2012.

While these statements differ from financial statements prepared in accordance with US GAAP, the modified cash basis of reporting revenues, expenses, and distributions is considered to be the most meaningful because monthly distributions to the Trust unitholders are based on net cash receipts. This comprehensive basis of accounting other than US GAAP corresponds to the accounting permitted for royalty trusts by the U.S. Securities and Exchange Commission as specified by Staff Accounting Bulletin Topic 12:E, Financial Statements of Royalty Trusts.

Use of Estimates

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

Note 3. Income Taxes

Federal Income Taxes

Tax counsel to the Trust advised the Trust at the time of formation that for U. S. federal income tax purposes, the Trust will be treated as a grantor trust and therefore is not subject to tax at the Trust level. Trust unitholders are treated as owning a direct interest in the assets of the Trust, and each Trust unitholder is taxed directly on his pro rata share of the income and gain attributable to the assets of the Trust and entitled to claim his pro rata share of the deductions and expenses attributable to the assets of the Trust. The income of the Trust is deemed to have been received or accrued by each unitholder at the time such income is received or accrued by the Trust rather than when distributed by the Trust.

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

Some Trust Units are held by a middleman, as such term is broadly defined in U.S. Treasury Regulations (and includes custodians, nominees, certain joint owners, and brokers holding an interest for a custodian in street name). Therefore, the Trustee considers the Trust to be a non-mortgage widely held fixed investment trust (“WHFIT”) for U.S. federal income tax purposes. The Bank of New York Mellon Trust Company, N.A., 919 Congress Avenue, Austin, Texas 78701, telephone number (512) 236-6545, is the representative of the Trust that will provide tax information in accordance with applicable U.S. Treasury Regulations governing the information reporting requirements of the Trust as a WHFIT. Notwithstanding the foregoing, the middlemen holding units on behalf of unitholders, and not the Trustee of the Trust, are solely responsible for complying with the information reporting requirements under the U.S. Treasury Regulations with respect to such units, including the issuance of IRS Forms 1099 and certain written tax statements. Unitholders whose units are held by middlemen should consult with such middlemen regarding the information that will be reported to them by the middlemen with respect to the Trust Units.

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

State Taxes

The Trust’s revenues are from sources in the state of California. Because it distributes all of its net income to unitholders, the Trust should not be taxed at the Trust level. California presently taxes income of nonresidents from real property located within the state. California taxes nonresidents on royalty income from the royalties located in that state and also imposes a corporate income tax which may apply to unitholders organized as corporations.

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

Note 4. Commodity Derivative Contracts

PCEC has outstanding commodity derivative contracts with Wells Fargo Bank, National Association in order to mitigate the effects of falling commodity prices through March 31, 2014. These contracts also limit the amount of cash available for distribution if prices increase above the fixed hedge price. The Trust is entitled to the effect of 2,000 barrels of daily swap volumes of ICE Brent oil at $115.00 per barrel ending March 31, 2014, proportional to the Trust's interest in the Developed Properties.

The amounts received or paid by PCEC from the commodity derivative contract counterparty upon settlement of the commodity derivative contracts will reduce or increase the operating expenses related to the Underlying Properties in calculating the NPI. The Trust received from PCEC net settlements related to derivative contracts of $4.6 million and $2.4 million in 2013 and 2012, respectively.

Note 5. Net Profits Interests and Overriding Royalty Interest

NPI

The amounts paid to the Trust for each Net Profits Interest are based on, among other things, the definitions of "gross profits" and "net profits" contained in the Conveyance and described below. Under the Conveyance, net profits are computed monthly. Each calendar month, 80% of the net profits from the sale of oil and natural gas production from the Developed Properties are paid to the Trust on or before the eighth business day after the last business day of the following month. For any monthly period during which costs for the Remaining Properties exceed gross proceeds, the Trust is entitled to receive the Royalty Interest Proceeds and the Trust continues to receive such proceeds until the first day of the month following an NPI Payout. In calendar months following an NPI Payout, 25% of the net profits from the sale of oil and natural gas production from all of the Remaining Properties will be paid to the Trust on or before the end of the following month.

"Gross profits" means the aggregate amount received by PCEC that is attributable to sales of oil and natural gas production from the Underlying Properties from and after April 1, 2012 (after deducting the appropriate share of all royalties and any overriding royalties, production payments and other similar charges and other than certain excluded proceeds including, with respect to the Remaining Properties, the Royalty Interest, to the extent paid, as described in the Conveyance), including all proceeds and consideration received (i) for advance payments, (ii) under take-or-pay and similar provisions of production sales contracts (when credited against the price for delivery of production) and (iii) under balancing arrangements. Gross profits do not include consideration for the transfer or sale of any Underlying Property by PCEC or any subsequent owner to any new owner, unless the Net Profits Interest in such Underlying Property is released (as is permitted under certain circumstances). Gross profits also do not include any amount for oil or natural gas lost in production or marketing or used by the owner of the Underlying Properties in drilling, production and plant operations.

"Net profits" means gross profits less the following costs, expenses and, where applicable, losses, liabilities and damages all as actually incurred by PCEC from and after April 1, 2012 and attributable to production from the Underlying Properties from and after April 1, 2012 (as such items are reduced by any offset amounts, as described in the Conveyance):

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

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

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

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

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

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

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

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

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

- all administrative hedge costs (in respect of commodity derivative contracts existing prior to the date of the conveyance, as further described in the Conveyance);

- all commodity derivative settlement costs (in respect of commodity derivative contracts existing prior to the date of the conveyance, as further described in the Conveyance);

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

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

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

The Trust is not liable to the owners of the Underlying Properties, PCEC, or any other operator for any operating, capital or other costs or liabilities attributable to the Underlying Properties. In the event that the net profits relating to the Developed Properties for any computation period is a negative amount, the Trust will receive no payment for the Developed Properties for that period, and any such negative amount will be deducted from gross profits for the Developed Properties in the following computation period for purposes of determining the net profits relating to the Developed Properties for that following computation period. In the event that the net profits relating to the Remaining Properties for any computation period is a negative amount, the Trust is entitled to receive the Royalty Interest Proceeds.

Gross profits and net profits are calculated on a cash basis, except that certain costs, primarily ad valorem taxes and expenditures of a material amount, may be determined on an accrual basis.

Overriding Royalty Interest

For any monthly period during which costs for the Remaining Properties exceed gross proceeds, the Trust is entitled to receive an amount equal to 7.5% of the proceeds attributable to the sale of all production from the Remaining Properties located on PCEC's Orcutt properties, including but not limited to PCEC's interest in such production (free of any production or development costs but bearing its proportionate share of production and property taxes and post-production costs) (the “Royalty Interest”).

Proceeds from the sale of oil, natural gas liquids and natural gas production from the Remaining Properties located on PCEC’s Orcutt properties in any calendar month means the amount calculated based on actual sales volumes from such properties, in each case after deducting the Trust’s proportionate share of:

- any taxes levied on the severance or production of the oil, natural gas liquids and natural gas produced from such properties and any property taxes attributable to the oil, natural gas liquids and natural gas produced from the such properties; and
- post-production costs, which will generally consist of costs incurred to gather, store, compress, transport, process, treat, dehydrate and market the oil, natural gas liquids and natural gas produced, as applicable (excluding costs for marketing services provided by PCEC).

Proceeds payable to the Trust from the sale of oil, natural gas liquids and natural gas production attributable to the Remaining Properties located on PCEC’s Orcutt properties in any calendar month are not subject to any deductions for any expenses attributable to exploration, drilling, development, operating, maintenance or any other costs incident to the production of oil, natural gas liquids and natural gas attributable to such properties, including any costs to drill, complete or plug and abandon a well. Additionally, costs associated with any completion activities will be borne by PCEC or any third-party operator of the well.

Note 6. Distributions to Unitholders

Each month, the Trustee determines the amount of funds available for distribution to the Trust unitholders. Available funds are the excess cash, if any, received by the Trust from the Conveyed Interests and other sources (such as interest earned on any amounts reserved by the Trustee) that month, over the Trust’s liabilities for that month, subject to adjustments for changes made by the Trustee during the month in any cash reserves established for future liabilities of the Trust. Distributions are made to the holders of Trust Units as of the applicable record date (generally within five business days after the last business day of each calendar month) and are payable on or before the 10th business day after the record date. The following table provides information regarding the Trust’s distributions paid during the year ended December 31, 2013 and for the period from May 8, 2012 through December 31, 2012.

Year Ended December 31, 2013

Declaration Date	Record Date	Payment Date	Distribution per Unit
December 21, 2012	December 31, 2012	January 15, 2013	$ 0.13941
January 25, 2013	February 4, 2013	February 14, 2013	$ 0.15116
February 25, 2013	March 7, 2013	March 14, 2013	$ 0.15403
March 26, 2013	April 5, 2013	April 15, 2013	$ 0.13655
April 22, 2013	May 2, 2013	May 14, 2013	$ 0.14600
May 24, 2013	June 3, 2013	June 14, 2013	$ 0.15270
June 25, 2013	July 5, 2013	July 15, 2013	$ 0.15721
July 26, 2013	August 5, 2013	August 14, 2013	$ 0.15462
August 27, 2013	September 6, 2013	September 16, 2013	$ 0.16990
September 24, 2013	October 4, 2013	October 14, 2013	$ 0.15761
October 24 , 2013	November 7, 2013	November 14, 2013	$ 0.14756
November 25, 2013	December 5, 2013	December 13, 2013	$ 0.13084

Period from May 8, 2012 to December 31, 2012

Declaration Date	Record Date	Payment Date	Distribution per Unit
May 21, 2012	May 31, 2012	June 15, 2012	$ 0.16234
June 19, 2012	June 29, 2012	July 16, 2012	$ 0.15392
July 20, 2012	July 31, 2012	August 14, 2012	$ 0.15187
August 21, 2012	August 31, 2012	September 14, 2012	$ 0.14850
September 18, 2012	September 28, 2012	October 12, 2012	$ 0.14987
October 19, 2012	October 31, 2012	November 14, 2012	$ 0.13939
November 20, 2012	November 30, 2012	December 14, 2012	$ 0.15228

Note 7. Related Party Transactions

Trustee Administrative Fee. Under the terms of the Trust Agreement, the Trust pays an annual administrative fee of $200,000 to the Trustee and $2,000 to the Delaware Trustee. During 2013, The Trust paid $200,000 to the Trustee and $2,000 to the Delaware Trustee. During 2012, The Trust paid $160,000 to the Trustee and $3,500 to the Delaware Trustee. In addition, the Trust paid an initial acceptance fee of $10,000 to the Trustee and $1,500 to the Delaware Trustee in 2012 for the first year of service.

PCEC Operating and Services Agreement and Fee. On May 8, 2012, the Trust and PCEC entered into an Operating and Services Agreement (the "Operating and Services Agreement"), pursuant to which PCEC provides the Trust with certain operating and informational service relating to the Conveyed Interests in exchange for a monthly fee. The PCEC operating and services fee is charged monthly in an amount equal to $83,333, which changed to $85,083 commencing on April 1, 2013. The monthly fee will be revised annually on April 1 based on changes to the Consumer Price Index. The PCEC operating and services agreement will terminate upon the termination of the Conveyed Interests unless earlier terminated by mutual agreement of the Trustee and PCEC.

The Trust paid PCEC $1.0 million and $0.6 million during 2013 and 2012, respectively. There were no payments to PCEC under the Operating and Services Agreement during the three months ended March 31, 2012.

Initial Public Offering. On May 8, 2012, PCEC sold 18,500,000 Trust Units to the public in connection with the IPO. The proceeds (net of underwriting discounts of approximately $23.0 million) received by PCEC (before expenses) from the IPO were approximately $346.9 million. The Trust received no proceeds from the sale of the Trust Units. The offering is further described in the Prospectus filed on May 4, 2012. In connection with the IPO, the Trust entered into the Operating and Services Agreement, the Registration Rights Agreement and the other agreements and instruments described herein and in the Prospectus.

Registration Rights Agreement. On May 8, 2012, the Trust and PCEC entered into a Registration Rights Agreement (the "Registration Rights Agreement") pursuant to which PCEC, its affiliates and any transferee of PCEC's Trust Units will be entitled, beginning 180 days after the date of the Registration Rights Agreement, to demand that the Trust use its reasonable best efforts to effect the registration of such holders' Trust Units under the Securities Act. The holders are entitled to demand a maximum of five such registrations. PCEC will bear all costs and expenses incidental to any registration statement, excluding certain internal expenses of the Trust, which will be borne by the Trust. Any underwriting discounts and commissions will be borne by the seller of the Trust Units. On June 17, 2013, pursuant to the registration rights agreement, the Trust filed a registration statement on Form S-3 registering the offering by PCEC of 20,083,158 Trust Units. The registration statement was declared effective on September 12, 2013.

Secondary Public Offering . On September 19, 2013, pursuant to the Registration Rights Agreement, the Trust, PCEC and the Selling Unitholders sold 13,500,000 Trust Units at a price of $17.10 per Trust unit ($16.416 per Trust unit, net of underwriting discounts and commissions). On September 23, 2013, PCEC distributed 11,216,661 Trust Units to the Other Selling Unitholders. Immediately following the distribution on September 23, 2013, the Other Selling Unitholders sold 8,500,000 Trust Units, and PCEC sold an additional 5,000,000 Trust Units, for a total sale of 13,500,000 Trust Units. PCEC retained 3,866,497 Trust Units, or 10% of the issued and outstanding Trust Units. The Trust received no proceeds from the sales of these Trust Units.

Note 8. Funding Commitment and Letter of Credit

PCEC has provided the Trust with a $1.0 million letter of credit to be used by the Trust in the event that its cash on hand (including available cash reserves) is not sufficient to pay ordinary course administrative expenses as they become due. Further, if the Trust requires more than the $1.0 million under the letter of credit to pay administrative expenses, PCEC has agreed to loan funds to the Trust necessary to pay such expenses. Any funds provided under the letter of credit or loaned by PCEC may only be used for the payment of current accounts or other obligations to trade creditors in connection with obtaining goods or services or for the payment of other accrued current liabilities arising in the ordinary course of the Trust's business, and may not be used to satisfy Trust indebtedness. If the Trust draws on the letter of credit or PCEC loans funds to the Trust, no further distributions will be made to Trust unitholders (except in respect of any previously determined monthly cash distribution amount) until such amounts drawn or borrowed, including interest thereon, are repaid. Any loan made by PCEC 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 PCEC and an unaffiliated third party. There were no borrowings outstanding at December 31, 2013.

Note 9. Subsequent Events

On January 15, 2014 the distribution of $0.12833 per Trust Unit, which was declared on December 23, 2013, was paid to Trust unitholders owning Trust Units as of January 6, 2014.

Subsequent to December 31, 2013, the Trust declared the following distributions:

Declaration Date	Record Date	Payment Date	Distribution per Unit
January 23, 2014	February 5, 2014	February 14, 2014	$ 0.13396
February 25, 2014	March 6, 2014	March 14, 2014	$ 0.12574

SUPPLEMENTAL INFORMATION

A. OIL AND NATURAL GAS DISCLOSURES (UNAUDITED)

Capitalized Costs Related to Oil and Natural Gas Producing Activities

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

	At December 31,	
	2013	2012
Investment in Conveyed Interests		
Proved	$ 271,192	$ 284,493
Total investment in Conveyed Interests	271,192	284,493
Less accumulated amortization	20,359	13,301
Net investment in Conveyed Interests	$ 250,833	$ 271,192

Oil and Natural Gas Reserve Quantities

Estimates of proved reserves attributable to the Trust were based on reports prepared by the Trust's independent petroleum engineers, Netherland, Sewell & Associates, Inc. ("NSAI"), including the report of NSAI dated March 4, 2014 filed herewith and included as Appendix A to the Trust's Annual Report on Form 10-K for the year ended December 31, 2013. Estimates were prepared in accordance with guidelines prescribed by the U.S. Securities and Exchange Commission and the Financial Accounting Standards Board, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations except by contractual arrangements.

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

As of December 31, 2013, all of the Underlying Properties' oil and gas reserves are attributable to properties within the United States. Proved reserves attributable to the Trust and related standardized measure valuations are prepared on an accrual basis, which is the basis on which PCEC and the Underlying Properties maintain their production records and is different from the basis on which the Trust production records are computed.

Unweighted average first-day-of-the-month crude oil and natural gas prices used to determine the total estimated proved reserves as of December 31, 2013 were ICE Brent crude oil price of $108.32 per barrel and Henry Hub natural gas prices of $3.67 per MMBtu. Unweighted average first-day-of-the-month crude oil and natural gas prices used in 2012 were $94.71 per barrel of oil for WTI spot price and Henry Hub natural gas prices of $2.76 per MMBtu.

The following is a summary of the changes in quantities of proved oil and gas reserves attributable to the Trust for the period from May 8, 2012 to December 31, 2013:

	Year Ended December 31, 2013			May 8 through December 31, 2012		
	Oil (MBbls)	Natural Gas (MMcf)	Total (MBOE)	Oil (MBbls)	Natural Gas (MMcf)	Total (MBOE)
Proved Reserves						
Beginning balance	10,591	1,581	10,855	—	—	—
Conveyance of NPI from PCEC	—	—	—	9,608	1,585	9,872
Revision of previous estimates	776	171	804	1,259	45	1,267
Conveyed interests volumes	(536)	(113)	(555)	(276)	(49)	(284)
Ending balance	10,831	1,639	11,104	10,591	1,581	10,855
Proved Developed Reserves						
Beginning balance	8,990	1,536	9,246	—	—	—
Ending balance	9,251	1,639	9,524	8,990	1,536	9,246
Proved Undeveloped Reserves						
Beginning balance	1,601	45	1,609	—	—	—
Ending balance	1,580	—	1,580	1,601	45	1,609

Revisions of Previous Estimates

In 2013, the Trust had revisions of 804 MBoe, which is primarily related to an increase in oil prices. In 2012, the Trust had positive revisions of 1,267 MBoe, primarily related to an increase in oil prices and better pricing from the sales contracts in the Orcutt properties.

Proved Undeveloped Reserves

Proved undeveloped reserves decreased by 29 MBoe to 1,580 MBoe at the end of 2013 compared to 1,609 MBoe at the end of 2012. There were no conversions of proved undeveloped reserves to developed reserves during the year ended December 31, 2013. As of December 31, 2013, there were no estimated proved undeveloped reserves that have remained undeveloped for more than five years, and it is expected that all estimated proved undeveloped reserves will be developed within the next five years.

Standardized Measure of Discounted Future Net Cash Flows

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

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves attributable to the Trust is as follows as of December 31, 2013:

Thousands of dollars	Year Ended December 31, 2013	May 8 through December 31, 2012
Future cash inflows	$ 1,095,229	$ 1,117,039
Future production expense	(30,948)	(36,361)
Future net cash flows	1,064,281	1,080,678
Discounted at 10% per year	(562,459)	(542,135)
Standardized measure of discounted future net cash flows	$ 501,822	$ 538,543

The changes in standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves attributable to the Trust for the year ended December 31, 2013 and the period from May 8, 2012 to December 31, 2012 are as follows:

Thousands of dollars	Year Ended December 31, 2013	May 8 through December 31, 2012
Beginning balance	$ 538,543	$ —
Conveyance of NPI from PCEC	—	441,166
Net change in sales and transfer prices, net of production expense	21,483	(19,069)
Accretion of discount	53,854	29,411
Revisions of previous estimates and other	(46,576)	125,990
Income from conveyed interests	(65,481)	(38,955)
Standardized measure	$ 501,822	$ 538,543

B. QUARTERLY SCHEDULE OF DISTRIBUTABLE INCOME (UNAUDITED)

	Year Ended December 31, 2013			
Thousands of dollars except per unit amounts	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2013:				
Income from conveyed interests	$ 17,459	$ 16,934	$ 18,737	$ 16,952
Distributable income	$ 17,154	$ 16,794	$ 18,587	$ 16,821
Distributable income per unit	$ 0.44460	$ 0.43525	$ 0.48173	$ 0.43601
2012 (a):				
Income from conveyed interests	$ —	$ 6,550	$ 17,692	$ 17,078
Distributable income	$ —	$ 6,264	$ 17,528	$ 17,036
Distributable income per unit	$ —	$ 0.16234	$ 0.45429	$ 0.44154

(a) The quarter ended June 30, 2012, reflects activities from May 8, 2012 to June 30, 2012 only.

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 Trust's disclosure controls and procedures (as defined in Rules 13a-15 and 15d-15 under the Exchange Act). Based on this evaluation, the Trustee has concluded that the disclosure controls and procedures of the Trust are effective as of the end of the period 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 Operating and Services Agreement and (iii) the Conveyance of the Net Profits Interest, the Trustee's disclosure controls and procedures related to the Trust necessarily rely on (A) information provided by PCEC, including information relating to results of operations, the costs and revenues attributable to the Trust's interest under the Conveyance and other operating and historical data, plans for future operating and capital expenditures, reserve information, information relating to projected production, and other information relating to the status and results of operations of the Underlying Properties and the Conveyed Interests, and (B) conclusions and reports regarding reserves by the Trust's independent reserve engineers.

Changes in Internal Control over Financial Reporting. During the quarter ended December 31, 2013, there was no change in the Trust's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the Trust's internal control over financial reporting. The Trustee notes for purposes of clarification that it has no authority over, and makes no statement concerning, the internal control over financial reporting of PCEC.

TRUSTEE'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The Trustee is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) promulgated under the Securities and Exchange Act of 1934, as amended. Internal control over financial reporting is a process to provide reasonable assurance regarding the reliability of financial reporting for external purposes in accordance with the modified cash basis of accounting. The Trustee conducted an evaluation of the effectiveness of the Trust's internal control over financial reporting based on the criteria established in *Internal Control—Integrated Framework (1992)* 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 (1992)* , the Trustee concluded that the Trust's internal control over financial reporting was effective as of December 31, 2013.

This Form 10-K does not include an attestation report of the Trust's registered public accounting firm as the Trust is an "emerging growth company" under the Jumpstart Our Business Startups Act.

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

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

Section 16(a) Beneficial Ownership Reporting Compliance

The Trust has no directors or officers. Accordingly, only holders of more than 10% of the Trust's units are required to file with the SEC initial reports of ownership of units and reports of changes in such ownership pursuant to Section 16 under the Securities Exchange Act of 1934. Based solely on a review of these reports and any such reports furnished to the Trustee, 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.

Audit Committee and Nominating Committee.

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

Code of Ethics

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

Item 11. Executive Compensation.

Pursuant to the Trust Agreement, the Trust pays an annual administrative fee of $200,000 to the Trustee. The net profits interest was conveyed to the Trust on May 8, 2012. The Trust does not have any executive officers, directors or employees. The Trust does not have a board of directors, and it does not have a compensation committee.

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

(a) Security Ownership of Certain Beneficial Owners.

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

Beneficial Owner	Trust Units Beneficially Owned	Percent of Class
Pacific Coast Energy Holdings LLC	3,866,497(1)	10.00%
Pacific Coast Energy Company LP(2)	3,866,497(1)	10.00%

(1) Reference is hereby made to the Schedule 13G filed by the reporting person on February 12, 2014 and the Forms 4 filed by the reporting person and others on May 10, 2012 for additional information regarding the beneficial ownership of the reporting persons.
(2) PCEC is managed by its general partner, PCEC (GP) LLC ("PCEC GP"). PCEC GP is wholly owned by Pacific Coast Energy Holdings LLC.

(b) Security Ownership of Management.

Not applicable.

(c) Changes in Control.

The registrant knows of no arrangement, including any pledge by any person of securities of the registrant or any of its parents, the operation of which may at a subsequent date result in a change of control of the registrant. See "Certain Relationships and Related Transactions, and Director Independence—Registration Rights."

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

Trustee Administrative Fee. Under the terms of the Trust Agreement, the Trust pays an annual administrative fee of $200,000 to the Trustee and $2,000 to the Delaware Trustee. During 2013, The Trust paid $200,000 to the Trustee and $2,000 to the Delaware Trustee. During 2012, The Trust paid $160,000 to the Trustee and $3,500 to the Delaware Trustee. In addition, the Trust paid an initial acceptance fee of $10,000 to the Trustee and $1,500 to the Delaware Trustee in 2012 for the first year of service.

PCEC Operating and Services Agreement and Fee. On May 8, 2012, the Trust and PCEC entered into an Operating and Services Agreement (the "Operating and Services Agreement"), pursuant to which PCEC provides the Trust with certain operating and informational service relating to the Conveyed Interests in exchange for a monthly fee. The PCEC operating and services fee is charged monthly in an amount equal to $83,333, which changed to $85,083 commencing on April 1, 2013. The monthly fee will be revised annually on April 1 based on changes to the Consumer Price Index. The PCEC operating and services agreement will terminate upon the termination of the Conveyed Interests unless earlier terminated by mutual agreement of the Trustee and PCEC.

During 2013 the Trust paid PCEC approximately $1.0 million. During 2012 the Trust paid PCEC approximately $0.6 million. There were no payments to PCEC under the Operating and Services Agreement during the three months ended March 31, 2012.

Initial Public Offering. On May 8, 2012, PCEC sold 18,500,000 Trust Units to the public in connection with the IPO. The proceeds (net of underwriting discounts of approximately $23.0 million) received by PCEC (before expenses) from the IPO were approximately $346.9 million. The Trust received no proceeds from the sale of the Trust Units. In connection with the IPO, the Trust entered into the Operating and Services Agreement, the Registration Rights Agreement and the other agreements and instruments described.

Registration Rights Agreement. On May 8, 2012, the Trust and PCEC entered into a Registration Rights Agreement (the “Registration Rights Agreement”) pursuant to which PCEC, its affiliates and any transferee of PCEC’s Trust Units will be entitled, beginning 180 days after the date of the Registration Rights Agreement, to demand that the Trust use its reasonable best efforts to effect the registration of such holders’ Trust Units under the Securities Act. The holders are entitled to demand a maximum of five such registrations. PCEC will bear all costs and expenses incidental to any registration statement, excluding certain internal expenses of the Trust, which will be borne by the Trust. Any underwriting discounts and commissions will be borne by the seller of the Trust Units. On June 17, 2013, pursuant to the registration rights agreement, the Trust filed a registration statement on Form S-3 registering the offering by PCEC of 20,083,158 Trust Units. The registration statement was declared effective on September 12, 2013.

Secondary Public Offering . On September 19, 2013, the Trust, PCEC and the Other Selling Unitholders entered into the Underwriting Agreement with the Underwriters, with respect to the Offering by PCEC and the Other Selling Unitholders. On September 23, 2013, PCEC distributed 11,216,661 Trust Units to the Other Selling Unitholders. Immediately following the distribution on September 23, 2013, the Other Selling Unitholders sold 8,500,000 Trust Units, and PCEC sold an additional 5,000,000 Trust Units, for a total sale of 13,500,000 Trust Units. PCEC retained 3,866,497 Trust Units, or 10% of the issued and outstanding Trust Units. The Trust received no proceeds from the sales of these Trust Units.

Director Independence

The Trust does 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. During the period from May 8, 2012 to December 31, 2013, PricewaterhouseCoopers LLP served as the Trust’s independent registered public accounting firm.

The following table presents the aggregate fees billed to the Trust for the year ended December 31, 2013 and 2012 by PricewaterhouseCoopers LLP:

	2013	2012
Audit fees(1)	$ 150,000	$ 125,000
Audit-related fees	—	—
Tax fees	—	—
All other fees	—	—
Total fees	$ 150,000	$ 125,000

(1) Fees for audit services consisted of the audit of the Trust’s financial statements.

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PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a)(1) Financial Statements

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

(a)(2) Schedules

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

(a)(3) Exhibits

See Exhibit Index.

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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.

PACIFIC COAST OIL TRUST

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

By: /s/ MIKE ULRICH
Mike Ulrich
Vice President

March 17, 2014

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

Appendix A

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

February 13, 2014

Mr. Mark L. Pease
BreitBurn Management Company, LLC
600 Travis Street, Suite 4800
Houston, Texas 77002

Mr. Michael J. Ulrich
The Bank of New York Mellon Trust Company, N.A.
as Trustee of Pacific Coast Oil Trust
Global Corporate Trust
919 Congress, Suite 500
Austin, Texas 78701

Gentlemen:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2013, to the Pacific Coast Oil Trust (PCOT) net profits and overriding royalty interest in certain oil and gas properties located in California. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by PCOT. Our report dated January 29, 2014, sets forth our estimates of proved reserves and future revenue to the Pacific Coast Energy Company LP (PCEC) interest in certain Orcutt properties located onshore in the Santa Maria Basin and certain East Coyote, Sawtelle, and West Pico properties located onshore in the Los Angeles Basin; these properties are referred to herein as the “Underlying Properties”. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for PCOT’s use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

The Underlying Properties are categorized as “Developed Properties” or “Remaining Properties” based on their reserves category as of December 31, 2011. The NPI entitle PCOT to receive 80 percent of the net profits from the sale of oil and natural gas production from Developed Properties and either 25 percent of the net profits from the sale of oil and natural gas production from Remaining Properties or a 7.5 percent overriding royalty interest in the Remaining Properties located in Orcutt Field for periods when net profits are not available.

We estimate the net reserves and future net revenue to the PCOT interest in these properties, as of December 31, 2013, to be:

	Net Reserves			Future Net Revenue (M$)	
Property Group/Category	**Oil (MBBL)**	**NGL (MBBL)**	**Gas (MMCF)**	**Total**	**Present Worth at 10%**
Developed Properties					
Proved Developed Producing	7,142.4	5.9	1,612.7	712,716.2	340,537.7
Proved Developed Non-Producing	1,396.6	0.0	23.7	133,722.5	67,166.2
Total Developed Properties	8,539.0	5.9	1,636.3	846,438.7	407,703.9
Remaining Properties					
Proved Developed Producing	343.1	0.0	2.5	33,280.5	22,125.2
Proved Developed Non-Producing	363.0	0.0	0.0	34,508.7	15,628.2
Proved Undeveloped	1,579.6	0.0	0.0	150,053.5	56,364.8
Total Remaining Properties	2,285.7	0.0	2.5	217,842.7	94,118.2
All Properties					
Proved Developed Producing	7,485.5	5.9	1,615.1	745,996.7	362,663.0
Proved Developed Non-Producing	1,759.6	0.0	23.7	168,231.2	82,794.3
Proved Undeveloped	1,579.6	0.0	0.0	150,053.5	56,364.8
Total All Properties	10,824.6	5.9	1,638.8	1,064,281.4	501,822.1

Totals may not add because of rounding.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

The estimates shown in this report are for proved reserves. As requested, probable and possible reserves that exist for these properties have not been included. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

The net reserves to the PCOT net profits interest are determined monthly using the economic interest method. By reserves category, the sum of the net profits payment and PCOT's share of the production and ad valorem taxes is divided by the effective price per barrel of oil equivalent. The resulting net equivalent reserves are then allocated between oil, NGL, and gas in the same proportion as the Underlying Properties.

Gross revenue is PCOT's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for PCOT's share of production taxes and ad valorem taxes but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2013. For oil and NGL volumes, the average ICE Brent crude price of $108.32 per barrel is adjusted for quality, transportation fees, and regional price differentials. For gas volumes, the average Henry Hub spot price of $3.670 per MMBTU is adjusted for energy content, transportation fees, and regional price differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $100.51 per barrel of oil, $95.77 per barrel of NGL, and $4.108 per MCF of gas.

Because PCOT owns no working interest in these properties, no operating costs or capital costs would be incurred. However, estimated operating costs and capital costs have been used to confirm economic producibility and determine economic limits for the properties. Operating costs used in this report are based on operating expense records of BreitBurn Management Company, LLC (BreitBurn). Operating costs and capital costs are not escalated for inflation. PCOT would not incur any costs due to abandonment, nor would it realize any salvage value for the lease and well equipment.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. Since PCOT owns a net profits and overriding royalty interest rather than a working interest in these properties, it would not incur any costs due to possible environmental liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the PCOT interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on PCOT receiving its net profits interest share of estimated future gross production.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred by the working interest owners in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from PCOT, PCEC, BreitBurn, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ J. Carter Henson, Jr.
J. Carter Henson, Jr., P.E. 73964
Senior Vice President

By: /s/ Mike K. Norton
Mike K. Norton, P.G. 441
Senior Vice President

Date Signed: February 13, 2014

Date Signed: February 13, 2014

JCH:MSS

Please be advised that the digital document you are viewing is provided by Netherland, Sewell & Associates, Inc. (NSAI) as a convenience to our clients. The digital document is intended to be substantively the same as the original signed document maintained by NSAI. The digital document is subject to the parameters, limitations, and conditions stated in the original document. In the event of any differences between the digital document and the original document, the original document shall control and supersede the digital document.

DEFINITIONS OF OIL AND GAS RESERVES

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir* . Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Instruction to paragraph (a)(2) : Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen* . Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate* . Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate* . The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

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

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Developed Producing Reserves — Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves — Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project* . A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

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

(10) *Economically producible* . The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)* . Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs* . Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or “G&G” costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well* . An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well* . An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field* . An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms “structural feature” and “stratigraphic condition” are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i) : The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

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

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

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

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

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) 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. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

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

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

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

(23) *Proved properties.* Properties with proved reserves.

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

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

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

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

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)
b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

- *a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*
- *b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*
- *c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*
- *d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*
- *e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*
- *f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

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

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

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

- (i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
- (ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*

- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

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

(32) *Unproved properties.* Properties with no proved reserves.

INDEX TO EXHIBITS

Exhibit Number	Description
1.1*	Underwriting Agreement dated as of May 2, 2012 among Pacific Coast Energy Company LP, PCEC (GP) LLC, Pacific Coast Oil Trust and Barclays Capital Inc., Citigroup Global Markets Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC, UBS Securities LLC and Wells Fargo Securities, LLC, as representatives of the several underwriters named therein (Incorporated herein by reference to Exhibit 1.1 to the Trust's Current Report on Form 8-K filed on May 8, 2012 (File No. 1-35532)).
1.2*	Underwriting Agreement dated as of September 19, 2013 among Pacific Coast Energy Company LP, PCEC (GP) LLC, Pacific Coast Oil Trust, the Selling Unitholders named therein and Morgan Stanley & Co. LLC, Barclays Capital Inc., J.P. Morgan Securities LLC, Wells Fargo Securities, LLC, UBS Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and RBC Capital Markets, LLC, as representatives of the several underwriters named therein (Incorporated herein by reference to Exhibit 1.1 to the Trust's Current Report on Form 8-K filed on September 25, 2013 (File No. 1-35532)).
3.1*	Certificate of Trust of Pacific Coast Oil Trust. (Incorporated herein by reference to Exhibit 3.1 to the Registration Statement on Form S-1, filed on January 6, 2012 (Registration No. 333-178928))
3.2*	Trust Agreement of Pacific Coast Oil Trust, dated January 3, 2012, among Pacific Coast Energy Company LP, Wilmington Trust, National Association, as Delaware trustee of Pacific Coast Oil Trust, and The Bank of New York Mellon Trust Company, N.A., as trustee of Pacific Coast Oil Trust. (Incorporated herein by reference to Exhibit 3.5 to the Registration Statement on Form S-1, filed on January 6, 2012 (Registration No. 333-178928))
3.3*	Amended and Restated Trust Agreement of Pacific Coast Oil Trust, dated May 8, 2012, among Pacific Coast Energy Company LP, Wilmington Trust, National Association, as Delaware trustee of Pacific Coast Oil Trust, and The Bank of New York Mellon Trust Company, N.A., as trustee of Pacific Coast Oil Trust. (Incorporated herein by reference to Exhibit 3.1 to the Trust's Current Report on Form 8-K filed on May 8, 2012 (File No. 1-35532))
3.4*	First Amendment to Amended and Restated Trust Agreement of Pacific Coast Oil Trust, dated June 15, 2012 (Incorporated by reference to Exhibit 3.1 to the Trust's Current Report on Form 8-K filed on June 19, 2012 (File No. 1-35532))
10.1*	Conveyance of Net Profits Interests and Overriding Royalty Interest, dated as of June 15, 2012, by and between Pacific Coast Energy Company LP and Pacific Coast Oil Trust (Incorporated herein by reference to Exhibit 10.1 to the Trust's Current Report on Form 8-K filed on June 19, 2012 (File No. 1-35532))
10.2*	Registration Rights Agreement, dated as of May 8, 2012, by and between Pacific Coast Energy Company LP and Pacific Coast Oil Trust (Incorporated herein by reference to Exhibit 10.2 to the Trust's Current Report on Form 8-K filed on May 8, 2012 (File No. 1-35532))
10.3*	Operating and Services Agreement, dated as of May 8, 2012, by and between Pacific Coast Energy Company LP and Pacific Coast Oil Trust (Incorporated by reference to Exhibit 10.3 to the Trust's Current Report on Form 8-K filed on May 8, 2012 (File No. 1-35532))
23.1	Consent of Netherland, Sewell & Associates, Inc.
23.2	Consent of PricewaterhouseCoopers LLP.
31.1	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1	Report of Netherland Sewell & Associates, Inc.

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

Exhibit 23.1

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

As independent petroleum engineers, we hereby consent to the inclusion or incorporation by reference in the Amendment No. 1 to the Registration Statement on Form S-3 (No. 333-189394) and the Annual Report on Form 10-K of Pacific Coast Oil Trust of information from our firm's reserves report dated February 13, 2014 and all references to our firm included in or made part of the Pacific Coast Oil Trust Annual Report on Form 10-K.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ J. Carter Henson Jr.
J. Carter Henson, Jr. P.E.
Senior Vice President

Houston, Texas
March 17, 2014

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Amendment No. 1 to the Registration Statement on Form S-3 (No. 333-189394) of Pacific Coast Oil Trust of our report dated March 17, 2014 relating to the financial statements, which appears in this Form 10-K.

/s/PricewaterhouseCoopers LLP
Los Angeles, California
March 17, 2014

EXHIBIT 31.1

CERTIFICATION

I, Mike Ulrich, certify that:

1. I have reviewed this annual report on Form 10-K of Pacific Coast Oil Trust, for which The Bank of New York Mellon Trust Company, N.A., acts as Trustee;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, distributable income and changes in Trust corpus of the registrant as of, and for, the periods presented in this report;

4. I am responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)), or for causing such controls and procedures to be established and maintained, for the registrant and I have:

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

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

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

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

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

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

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

In giving the foregoing certifications in paragraphs 4 and 5 I have relied to the extent I consider reasonable on information provided to me by Pacific Coast Energy Company LP.

Date: March 17, 2014

/s/ MIKE ULRICH
Mike Ulrich
Vice President
The Bank of New York Mellon Trust Company, N.A., as Trustee

EXHIBIT 32.1

CERTIFICATION PURSUANT TO SECTION 906

OF THE SARBANES-OXLEY ACT OF 2002 (18 U.S.C. SECTION 1350)

In connection with the Annual Report of Pacific Coast Oil Trust (the “Trust”) on Form 10-K for the year ended December 31, 2013 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), the undersigned, not in its individual capacity but solely as the Trustee of the Trust, certifies pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to its knowledge:

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

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

The above certification is furnished solely pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. 1350) and is not being filed as part of the Form 10-K or as a separate disclosure document.

The Bank of New York Mellon Trust Company,
N.A., Trustee for Pacific Coast Oil Trust

Date: March 17, 2014

By: /s/ MIKE ULRICH
Mike Ulrich
Vice President and Trust Officer

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

February 13, 2014

Mr. Mark L. Pease
BreitBurn Management Company, LLC
600 Travis Street, Suite 4800
Houston, Texas 77002

Mr. Michael J. Ulrich
The Bank of New York Mellon Trust Company, N.A.
as Trustee of Pacific Coast Oil Trust
Global Corporate Trust
919 Congress, Suite 500
Austin, Texas 78701

Gentlemen:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2013, to the Pacific Coast Oil Trust (PCOT) net profits and overriding royalty interest in certain oil and gas properties located in California. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by PCOT. Our report dated January 29, 2014, sets forth our estimates of proved reserves and future revenue to the Pacific Coast Energy Company LP (PCEC) interest in certain Orcutt properties located onshore in the Santa Maria Basin and certain East Coyote, Sawtelle, and West Pico properties located onshore in the Los Angeles Basin; these properties are referred to herein as the "Underlying Properties". The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for PCOT's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

The Underlying Properties are categorized as "Developed Properties" or "Remaining Properties" based on their reserves category as of December 31, 2011. The net profits interests entitle PCOT to receive 80 percent of the net profits from the sale of oil and natural gas production from Developed Properties and either 25 percent of the net profits from the sale of oil and natural gas production from Remaining Properties or a 7.5 percent overriding royalty interest in the Remaining Properties located in Orcutt Field for periods when net profits are not available.

We estimate the net reserves and future net revenue to the PCOT interest in these properties, as of December 31, 2013, to be:

	Net Reserves			Future Net Revenue (M$)	
Property Group/Category	**Oil (MBBL)**	**NGL (MBBL)**	**Gas (MMCF)**	**Total**	**Present Worth at 10%**
Developed Properties					
Proved Developed Producing	7,142.4	5.9	1,612.7	712,716.2	340,537.7
Proved Developed Non-Producing	1,396.6	0.0	23.7	133,722.5	67,166.2
Total Developed Properties	8,539.0	5.9	1,636.3	846,438.7	407,703.9
Remaining Properties					
Proved Developed Producing	343.1	0.0	2.5	33,280.5	22,125.2
Proved Developed Non-Producing	363.0	0.0	0.0	34,508.7	15,628.2
Proved Undeveloped	1,579.6	0.0	0.0	150,053.5	56,364.8
Total Remaining Properties	2,285.7	0.0	2.5	217,842.7	94,118.2
All Properties					
Proved Developed Producing	7,485.5	5.9	1,615.1	745,996.7	362,663.0
Proved Developed Non-Producing	1,759.6	0.0	23.7	168,231.2	82,794.3
Proved Undeveloped	1,579.6	0.0	0.0	150,053.5	56,364.8
Total All Properties	10,824.6	5.9	1,638.8	1,064,281.4	501,822.1

Totals may not add because of rounding.

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nsai@nsai-petro.com
netherlandsewell.com

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

The estimates shown in this report are for proved reserves. As requested, probable and possible reserves that exist for these properties have not been included. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

The net reserves to the PCOT net profits interest are determined monthly using the economic interest method. By reserves category, the sum of the net profits payment and PCOT's share of the production and ad valorem taxes is divided by the effective price per barrel of oil equivalent. The resulting net equivalent reserves are then allocated between oil, NGL, and gas in the same proportion as the Underlying Properties.

Gross revenue is PCOT's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for PCOT's share of production taxes and ad valorem taxes but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2013. For oil and NGL volumes, the average ICE Brent crude price of $108.32 per barrel is adjusted for quality, transportation fees, and regional price differentials. For gas volumes, the average Henry Hub spot price of $3.670 per MMBTU is adjusted for energy content, transportation fees, and regional price differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $100.51 per barrel of oil, $95.77 per barrel of NGL, and $4.108 per MCF of gas.

Because PCOT owns no working interest in these properties, no operating costs or capital costs would be incurred. However, estimated operating costs and capital costs have been used to confirm economic producibility and determine economic limits for the properties. Operating costs used in this report are based on operating expense records of BreitBurn Management Company, LLC (BreitBurn). Operating costs and capital costs are not escalated for inflation. PCOT would not incur any costs due to abandonment, nor would it realize any salvage value for the lease and well equipment.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. Since PCOT owns a net profits and overriding royalty interest rather than a working interest in these properties, it would not incur any costs due to possible environmental liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the PCOT interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on PCOT receiving its net profits interest share of estimated future gross production.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred by the working interest owners in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from PCOT, PCEC, BreitBurn, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ J. Carter Henson, Jr.
J. Carter Henson, Jr., P.E. 73964
Senior Vice President

By: /s/ Mike K. Norton
Mike K. Norton, P.G. 441
Senior Vice President

Date Signed: February 13, 2014

Date Signed: February 13, 2014

JCH:MSS

NETHERLAND, SEWELL & ASSOCIATES, INC.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir* . Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

- (i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
- (ii) Same environment of deposition;
- (iii) Similar geological structure; and
- (iv) Same drive mechanism.

Instruction to paragraph (a)(2) : Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen* . Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate* . Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate* . The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

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

- (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
- (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Developed Producing Reserves — Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves — Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project* . A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

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

(10) *Economically producible* . The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)* . Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs* . Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or “G&G” costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well* . An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well* . An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field* . An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:

(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i) : The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and

b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

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

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

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

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

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) 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. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

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

(i) The area of the reservoir considered as proved includes:

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

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

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

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90%

probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology*. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

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

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

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. *Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*
b. *Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. *Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*
b. *Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*
c. *Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*
d. *Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*
e. *Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*
f. *Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

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

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

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

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

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

(32) *Unproved properties.* Properties with no proved reserves.