Pacific Coast Oil Trust
Form S-1/A
April 20, 2012
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As filed with the Securities and Exchange Commission on April 19, 2012

Registration No. 333-178928

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

AMENDMENT NO. 5

TO

Form S-1

REGISTRATION STATEMENT

UNDER

THE SECURITIES ACT OF 1933

Pacific Coast Oil Trust	**Pacific Coast Energy Company LP**
(Exact Name of co-registrant as specified in its charter)	*(Exact Name of co-registrant as specified in its charter)*
Delaware	**Delaware**
(State or other jurisdiction of incorporation or organization)	*(State or other jurisdiction of incorporation or organization)*
1311	**1311**
(Primary Standard Industrial Classification Code Number)	*(Primary Standard Industrial Classification Code Number)*
80-6216242	**20-1241171**
(I.R.S. Employer Identification No.)	*(I.R.S. Employer Identification No.)*
919 Congress Avenue, Suite 500	**515 South Flower Street, Suite 4800**
Austin, Texas 78701	**Los Angeles, California 90071**
(512) 236-6599	**(213) 225-5900**
	Attention: Gregory
	C. Brown
(Address, including zip code, and	*(Address, including zip code, and*
telephone number, including	*telephone number, including*
area code, of co-registrant s Principal Executive Offices)	*area code, of co-registrant s Principal Executive Offices)*
The Bank of New York Mellon Trust	**Gregory C. Brown**

Company, N.A., Trustee

919 Congress Avenue, Suite 500

Austin, Texas 78701

(512) 236-6599

Attention: Michael J. Ulrich

(Name, address, including zip code, and

telephone number,

including area code, of agent for service)

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Approximate date of commencement of proposed sale to the public: As soon as practicable after this Registration Statement becomes effective.

If any of the securities being registered on this form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, check the following box. ¨

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, please check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

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 þ Smaller reporting company ¨

(Do not check if a smaller reporting company)

CALCULATION OF REGISTRATION FEE

Title of Each Class of Securities to be Registered	Proposed Maximum Aggregate Offering Price[(1)(2)]	Amount of Registration Fee[(3)]
Units of Beneficial Interest in Pacific Coast Oil Trust	$422,625,000	$48,432.83

(1) Includes trust units issuable upon exercise of the underwriters option to purchase additional trust units.

(2) Estimated solely for the purpose of calculating the registration fee pursuant to Rule 457(o).

(3) The co-registrants have previously paid $39,537 in connection with their Registration Statement on Form S-1 (File No. 333-178928) filed on January 6, 2012.

The co-registrants hereby amend this Registration Statement on such date or dates as may be necessary to delay its effective date until the co-registrants shall file a further amendment which specifically states that this Registration Statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933 or until the Registration Statement shall become effective on such date as the Securities and Exchange Commission, acting pursuant to said Section 8(a), may determine.

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The information in this prospectus is not complete and may be changed. These securities may not be sold until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these in any state where the offer or sale is not permitted.

Subject to Completion, dated April 19, 2012

PROSPECTUS

Trust Units

This is the initial public offering of units of beneficial interest in Pacific Coast Oil Trust, or the trust. Pacific Coast Energy Company LP, or PCEC, has formed the trust and, immediately prior to the closing of this offering, will convey, or cause to be conveyed, interests in oil properties to the trust in exchange for trust units. PCEC is offering trust units to be sold in this offering and will receive all of the proceeds derived therefrom. After the offering, PCEC will own trust units, or trust units if the underwriters exercise their option to purchase additional trust units from PCEC. No public market currently exists for the trust units. PCEC is a privately held Delaware limited partnership engaged in the production and development of oil and natural gas from properties located onshore in California. The trust is an emerging growth company.

The trust has applied to list the trust units on the New York Stock Exchange under the symbol ROYT.

PCEC expects that the public offering price will be between $ and $ per trust unit.

The trust units. Trust units are equity securities of the trust and represent undivided beneficial interests in the trust assets. They do not represent any interest in PCEC.

The trust. The trust will own interests in properties held by PCEC in California, or the Underlying Properties, as of April 1, 2012, the date of the conveyance of the interests to the trust. The Underlying Properties consist of (i) the proved developed reserves as of December 31, 2011 on the Underlying Properties, or the Developed Properties, and (ii) all other development potential on the Underlying Properties, or the Remaining Properties. The interests will entitle the trust to receive 80% of the net profits from the sale of oil and natural gas production from the Developed Properties. The trust will also be entitled to receive 7.5% of the proceeds (free of any production or development costs but bearing its proportionate share of production and property taxes and post-production costs), or the Royalty Interest, attributable to the sale of all oil and gas production from the portion of the Remaining Properties located on PCEC s Orcutt properties, including but not limited to PCEC s interest in such production. Alternatively, depending on conditions described elsewhere in this prospectus, the trust will receive instead of payments associated with the Remaining Properties pursuant to the Royalty Interest, or the Royalty Interest Proceeds, 25% of the net profits from the sale of oil and natural gas production from all of the Remaining Properties. PCEC expects the trust to receive payments associated with the Royalty Interest Proceeds until approximately 2020. The conveyed net profits interests are together referred to as the Net Profits Interests.

The trust unitholders. As a trust unitholder, you will receive monthly cash distributions from the proceeds that the trust receives from PCEC pursuant to the Net Profits Interests and/or the Royalty Interest. The trust s ability to pay monthly cash distributions will depend on its receipt of net profits and royalties attributable to the Net Profits Interests and/or the Royalty Interest, which will depend on, among other things, volumes produced, wellhead prices, price differentials, production and development costs, potential reductions or suspensions of production, permitting and the amount and timing of trust administrative expenses.

Investing in the trust units involves a high degree of risk. Please read *Risk Factors* *beginning on page 18 of this prospectus. These risks include the following:*

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

Estimates of future cash distributions to trust unitholders are based on assumptions that are inherently subjective.

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

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

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, net profits interests 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 trust has not requested a ruling from the Internal Revenue Service, or 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.

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.

	Per Trust Unit	**Total**
Price to the public	$	$
Underwriting discounts and commissions[1]	$	$
Proceeds to PCEC, before expenses	$	$

(1) Excludes a structuring fee of % of the gross proceeds of the offering payable to Barclays Capital Inc. by PCEC for the evaluation, analysis and structuring of the trust.

PCEC has granted the underwriters an option to purchase up to an additional trust units from it on the same terms and conditions set forth above if the underwriters sell more than trust units in this offering.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

Barclays, on behalf of the underwriters, expects to deliver the trust units on or about , 2012.

Barclays Citigroup BofA Merrill Lynch J.P. Morgan UBS Investment Bank Wells Fargo Securities

RBC Capital Markets Baird Stifel Nicolaus Weisel Oppenheimer & Co. Janney Montgomery Scott

Prospectus dated , 2012

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Important Notice About Information in This Prospectus

PCEC and the trust have not, and the underwriters have not, authorized anyone to provide you with additional or different information. If anyone provides you with additional, different or inconsistent information, you should not rely on it. This prospectus is not an offer to sell or a solicitation of an offer to buy the trust units in any jurisdiction where such offer and sale would be unlawful. You should not assume that the information contained in this prospectus is accurate as of any date other than the date on the front of this document. The business, financial condition, results of operations and prospects of PCEC and the trust may have changed since such date.

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PROSPECTUS SUMMARY

This summary highlights information contained elsewhere in this prospectus. To understand this offering fully, you should read the entire prospectus carefully, including the risk factors, the summary reserve reports and the financial statements and notes to those statements. Unless otherwise indicated, all information in this prospectus assumes (a) an initial public offering price of $ per trust unit (the midpoint of the price range set forth on the cover of this prospectus) and (b) no exercise of the underwriters option to purchase additional trust units.

Unless otherwise indicated, as used in this prospectus, (i) PCEC refers to Pacific Coast Energy Company LP and its subsidiaries, including any predecessor entities of PCEC, (ii) the Underlying Properties refers to the Orcutt properties located onshore in the Santa Maria Basin and the East Coyote, Sawtelle and West Pico properties located onshore in the Los Angeles Basin held by PCEC and (iii) proved developed reserves refers to proved developed producing and proved developed non-producing reserves, as such terms are defined by the Securities and Exchange Commission, or the SEC.

References in this prospectus to future production from, or future reserves or revenues attributable to, PCEC s East Coyote and Sawtelle properties reflect that PCEC s average interest in such properties increased from approximately 5.0% to approximately 37.6% as of April 1, 2012. We refer to this increase in PCEC s interest as the East Coyote and Sawtelle Reversion. However, references in this prospectus to historical production, reserves or revenues do not give effect to the East Coyote and Sawtelle Reversion.

Netherland, Sewell & Associates, Inc., referred to in this prospectus as Netherland Sewell, an independent engineering firm, provided the estimates of proved oil and natural gas reserves as of December 31, 2011 included in this prospectus. These estimates are contained in summaries prepared by Netherland Sewell of its reserve reports as of December 31, 2011 for the Underlying Properties held by PCEC and the Conveyed Interests (as defined below) held by the trust. These summaries are located at the back of this prospectus in Annexes A and B and are collectively referred to in this prospectus as the reserve reports. You will find definitions for terms relating to the oil and natural gas business in Glossary of Certain Oil and Natural Gas Terms.

Pacific Coast Oil Trust

Pacific Coast Oil Trust is a Delaware statutory trust formed by PCEC in January 2012 to own interests in the Underlying Properties. The Underlying Properties consist of (i) the proved developed reserves as of December 31, 2011 on the Underlying Properties, which we refer to as the Developed Properties, and (ii) all other development potential on the Underlying Properties, which we refer to as the Remaining Properties. Production from the Developed Properties that will be attributable to the trust is produced from wells that, because they have already been drilled, require limited additional capital expenditures. As a result, the Developed Properties are projected to have positive net profits immediately upon conveyance to the trust. Production from the Remaining Properties that will be attributable to the trust will require capital expenditures for the drilling of wells and installation of infrastructure. PCEC will supply required capital on behalf of the trust during this period; however, because the costs initially incurred will exceed gross proceeds, the Remaining Properties will 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 will be 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, then the net profits interests on the Remaining Properties will be paid out in place of the royalty interests, as described below. We refer to the net

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profits interests and royalty interest conveyed to the trust as the Net Profits Interests and Royalty Interest, respectively. These interests, which we refer to collectively as 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, which we refer to as 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 will not reduce net profits calculated for the other. The amount of Royalty Interest Proceeds paid will be 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 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 future cumulative net profits for such properties exceed the cumulative total excess costs for such properties.

For any monthly period during which costs for the Remaining Properties exceed gross proceeds, the trust would be entitled to receive the Royalty Interest Proceeds, and the trust would continue 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, an event we refer to as an NPI Payout. 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 2020. The trust would be entitled to receive the Royalty Interest Proceeds again if, in any monthly period following an NPI Payout, costs for the Remaining Properties exceeded gross proceeds. Please read Computation of Net Profits and Royalties.

The Net Profits Interests will be entitled to a share of the profits from and after April 1, 2012 attributable to production from the Underlying Properties from and after April 1, 2012. In addition, from and after April 1, 2012, if the Remaining Properties are not entitled to a share of such net profits because costs exceed gross profits, then the Royalty Interest will be entitled to the Royalty Interest Proceeds until the NPI Payout occurs.

The trust will make 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 the last business day of each calendar month) on or before the 10th business day after the record date. 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.

Underlying Properties

The Underlying Properties are located in California in the Santa Maria and Los Angeles Basins, both of which are characterized by long producing histories. PCEC operated approximately 98% of the average daily production from the Underlying Properties for the month ended December 31, 2011. The Underlying Properties held approximately 34.1 MMBoe in proved reserves as of December 31, 2011, which were approximately 98% oil and 62% proved developed. The Underlying Properties produced approximately 3,458 Boe/d from 276 gross (215 net) producing wells for the month ended December 31, 2011. The following table summarizes certain information regarding the proved reserves and production associated with the Underlying Properties as of and for the periods indicated. The reserve reports were prepared by Netherland Sewell in accordance with criteria established by the SEC. For information regarding proved reserves and production related to the Conveyed Interests, please read The Underlying Properties.

					Underlying Properties Proved Reserves as of December 31, 2011[1]			
Properties	**PCEC Operated**		**Average Daily Net Production for Month Ended December 31, 2011 (Boe/d)**	**Producing Wells**	**Total (MBoe)[2]**	**% Oil**	**% Proved Developed Reserves**	**R/P Ratio as of December 31, 2011[3]**
Orcutt, Conventional	2004	Present	2,093	125	11,737	100%	100%	15.4
West Pico[4]	1993	Present	628	40	3,808	82%	65%	16.6
Orcutt, Diatomite	2005	Present	673	54	15,563	100%	25%	63.3
East Coyote[5]	1999	April 2012	27	46	1,674	100%	100%	169.9
Sawtelle[5]	1993	April 2012	37	11	1,346	92%	100%	99.7
Total			3,458	276	34,128	98%	62%	27.0

(1) In accordance with the rules and regulations promulgated by the SEC, the proved reserves presented above were determined using the twelve month unweighted arithmetic average of the first-day-of-the-month price for the period from January 1, 2011 through December 31, 2011, without giving effect to any hedge transactions, and were held constant for the life of the properties. This yielded average index prices, before adjustments, of $95.97 per Bbl and $4.12 per MMBtu.

(2) Oil equivalents in the table are the sum of the Bbls of oil and the Boe of the stated Mcfs of natural gas, calculated on the basis that six Mcfs of natural gas are the energy equivalent of one Bbl of oil.

(3) The R/P ratio, or the reserves-to-production ratio, is a measure of the number of years that a specified reserve base could support a fixed amount of production. This ratio is calculated by dividing total estimated proved reserves of the subject properties at the end of a period by annual total production for the prior twelve months. Because production rates naturally decline over time, the R/P ratio is not a useful estimate of how long properties should economically produce.

(4) The West Pico property consists of the West Pico Unit and includes three wells owned by the Stocker JV (a joint venture between PCEC and Plains Exploration & Production Company, or PXP).

(5) In connection with the East Coyote and Sawtelle Reversion, BreitBurn Energy Partners L.P., or BBEP, became the operator of these properties effective April 2012.

The Santa Maria Basin is one of California s largest and longest producing oil regions. The Santa Maria Basin has produced over one billion Bbls of oil since its discovery in 1901 and is characterized by oilfields with long production histories. PCEC produces oil and natural gas from its Orcutt properties in the Santa Maria Basin. Currently, a majority of production in the Orcutt oilfield is produced from formations utilizing conventional production methods. Beginning in the 1990s, companies in California began to focus on the development of the Diatomite formations, a typically shallow zone. The Orcutt Diatomite formation lies approximately 100 to 900 feet below the surface and is produced by utilizing cyclic steam injection. PCEC utilizes primarily water flooding to produce oil from its conventional Orcutt properties, and since 2005, has utilized cyclic steam injection to produce oil from the Diatomite formation in its Orcutt properties.

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Similar to the Santa Maria Basin, the Los Angeles Basin is characterized by its mature oilfields with long production histories. The Los Angeles Basin has produced more than nine billion Bbls of oil since its discovery in 1892. Within the Los Angeles Basin, PCEC produces oil and natural gas from its conventional West Pico, East Coyote and Sawtelle properties.

The estimated future production for the Underlying Properties highlights the predictable production and long lived reserves that will constitute the Conveyed Interests. The following graph shows estimated average daily production and decline rates of total proved reserves proportional to the trust (for 80% of proved developed reserves and 25% of proved undeveloped reserves as of December 31, 2011) based on the pricing and other assumptions set forth in the reserve report for the Underlying Properties. This graph presents the total proved volumes and decline rates as reflected in the reserve report for the Underlying Properties broken down by two reserve categories (proved developed and proved undeveloped reserves) as of December 31, 2011. This graph does not reflect any probable or possible reserves.

(1) Represents 80% of sales volumes from the proved developed reserves as of December 31, 2011.
(2) Represents 25% of sales volumes from the proved undeveloped reserves as of December 31, 2011.

The graph above provides data relating to projected production proportional to the trust, based upon the production projected for the Underlying Properties. For a presentation of the reserves attributable to the Underlying Properties and the Conveyed Interests, please read the introduction to The Underlying Properties. For a discussion of the calculation of the reserves attributable to the trust, please read The Underlying Properties Computation of Proved Reserves Attributable to the Conveyed Interests.

Key Investment Considerations

The following are some key investment considerations related to the Underlying Properties, the Conveyed Interests and the trust units:

Mature, primarily oil asset base with predictable production and long lived reserves. The Underlying Properties consist primarily of oil reserves and prospects in multiple geologic horizons in mature oilfields located onshore in California. As of December 31, 2011, proved reserves were comprised of approximately 98% oil. Long producing histories in the Santa Maria and Los Angeles Basins provide for well established production profiles and increased certainty of production estimates.

Substantial proved developed oil reserves. Proved developed reserves are generally considered the most valuable and lowest risk category of reserves. As of December 31, 2011, approximately 62% of the volumes of the proved reserves associated with the Underlying Properties and 81% of the volumes of the proved reserves associated with the trust were attributed to proved developed reserves. As of December 31, 2011, the Underlying Properties had a proved reserves to production ratio of 27.0 years and proved developed reserves to production ratio of 16.7 years.

Significant resource base with considerable development opportunities. PCEC believes that the Underlying Properties are likely to offer economic development opportunities in the future that are not reflected in existing proved reserves and could significantly increase future reserves and production. The Diatomite formation in PCEC s Orcutt properties offers significant development opportunities for the Underlying Properties. PCEC expects to implement several projects starting in 2012 to increase production from the Underlying Properties. These projects include developing in the near term 38 wells in the Diatomite formation. Further projects may include permitting and drilling additional Diatomite wells in areas not currently developed. In addition to these projects, future increases in estimated oil recovery factors in the Santa Maria and Los Angeles Basins may significantly increase reserves and production. Such increases in recovery factors may occur through, among other means, technological advances, implementation of additional enhanced recovery techniques, infill drilling and production outperformance.

Significant percentage of operated properties. PCEC owned a majority working interest in, and operated approximately 98% of the average daily production from, the Underlying Properties for the month ended December 31, 2011. This high level of operational control allows PCEC to use its technical and operational expertise to manage overhead, production and drilling costs and capital expenditures and to control the timing and amount of discretionary expenditures for exploration, exploitation and development activities. PCEC is not under any obligation to drill in order to hold leases since 100% of the properties are already held by production or owned in fee. In addition, PCEC s management team has managed the operations of the Underlying Properties for an average of twelve years.

High operating margins provide strong cash flow profile. The Underlying Properties have historically generated substantial operating margins. Lease operating expenses and property and other taxes related to the Underlying Properties averaged $32.38 per Boe for the year ended December 31, 2011. During the same period, the realized sales price for oil and natural gas (excluding the effects of hedges) averaged $87.92 per Boe, providing an operating margin of $55.54 per Boe, or 63%.

Initial downside crude oil price protection with long-term direct exposure to oil prices. To mitigate the negative effects of a possible decline in oil prices on distributable income to the trust, PCEC has entered into commodity derivative contracts with respect to 2,000 barrels of daily swap volumes of Brent crude oil at $115.00 per barrel during the twenty-four months ending March 31, 2014, which represents approximately 70% of expected oil and natural gas production from April 1, 2012 through March 31, 2014 from the proved developed reserves as of December 31, 2011, proportional to the trust s interest in the Developed Properties. These commodity derivative contracts are swaps that mitigate the risk of oil price declines to the trust.

Alignment of interests between PCEC and the trust unitholders. Immediately following the closing of this offering, PCEC will have an effective ownership of approximately % of the Underlying Properties reserves proportional to the net profits and royalties attributable to the sale of oil and natural gas produced from the Underlying Properties, including its retained interest in the Developed Properties, its retained interest in the Remaining Properties and its ownership of approximately % of the trust units. By having a material, direct economic interest in the Underlying Properties, PCEC is incentivized

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to deploy capital on projects where it is likely to successfully increase production or reserves at attractive returns. PCEC expects to maintain a strong financial position, including a borrowing base credit facility, which will allow it and the trust to capitalize on future projects on the Underlying Properties.

Formation Transactions

At or prior to the closing of this offering, the following transactions, which are referred to herein as the Formation Transactions, will occur:

PCEC will convey, or cause to be conveyed, to the trust the Conveyed Interests effective as of April 1, 2012 in exchange for trust units in the aggregate, representing all of the outstanding trust units of the trust.

PCEC will sell trust units offered hereby, representing an % interest in the trust. PCEC will also make available during the 30-day option period up to trust units for the underwriters to purchase at the initial offering price to cover over-allotments. PCEC intends to use the proceeds of the offering as disclosed under Use of Proceeds.

PCEC and the trust will enter into an operating and services agreement that will define the services PCEC will provide to the trust on an ongoing basis as well as its compensation. Please read The Trust.

Structure of the Trust

The following chart shows the relationship of PCEC, the trust and the public trust unitholders after the closing of this offering.

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Risk Factors

An investment in the trust units involves risks associated with fluctuations in commodity prices, the operation of the Underlying Properties, certain regulatory and legal matters, the structure of the trust and the tax characteristics of the trust units. Please read carefully the risks described under Risk Factors on page 18 of this prospectus.

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

- Estimates of future cash distributions to trust unitholders are based on assumptions that are inherently subjective.

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

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

- 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.

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

- 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, net profits interests 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.

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

- The amount of cash available for distribution by the trust will be reduced by the amount of any costs and expenses related to the Underlying Properties and other costs and expenses incurred by the trust.

- 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.

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

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.

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

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

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.

There has been no public market for the trust units, and accordingly the value after this offering may differ from the price in the offering.

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.

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.

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.

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

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

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 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.

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

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 may be treated as an unsecured creditor with respect to the Net Profits Interests.

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 receipt of payments by PCEC based on any commodity derivative contract will depend upon the financial position of the 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.

The trust has not requested a ruling from the Internal Revenue Service, or the IRS, regarding the tax treatment of the trust. If the IRS were to determine (and be sustained in that determination) that the

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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.

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.

You will be required to pay taxes on your share of the trust s income even if you do not receive any cash distributions from the trust.

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

The trust will allocate 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.

As a result of investing in trust units, you may become subject to state and local taxes and return filing requirements in California.

Summary Historical and Unaudited Pro Forma Financial, Operating and Reserve Data of PCEC

The summary historical audited financial data of PCEC as of December 31, 2011 and 2010 and for the three-year period ended December 31, 2011 have been derived from PCEC s audited financial statements.

The summary unaudited pro forma financial data as of and for the year ended December 31, 2011 has been derived from the unaudited pro forma financial statements of PCEC included elsewhere in this prospectus. The pro forma data has been prepared as if the conveyance of the Conveyed Interests and the offer and sale of the trust units and application of the net proceeds therefrom had taken place (i) on December 31, 2011, in the case of pro forma balance sheet information as of December 31, 2011, and (ii) as of January 1, 2011, in the case of pro forma statement of earnings for the year ended December 31, 2011. The summary historical and unaudited pro forma financial, operating and reserve data presented below should be read in conjunction with Pacific Coast Energy Company LP Selected Historical and Unaudited Pro Forma Financial Data of PCEC, Information About Pacific Coast Energy Company LP Management s Discussion and Analysis of Financial Condition and Results of Operations of PCEC and the accompanying financial statements and related notes of PCEC included elsewhere in this prospectus.

Summary Historical and Unaudited Pro Forma Financial Data of PCEC

	PCEC Pro Forma for the Offering (Including the Conveyance of the Conveyed Interests) Year Ended December 31, 2011	PCEC Year Ended December 31,		
		2011	2010	2009
(In thousands)	**(Unaudited)**			
Total revenues and other income	$ 97,004	$ 110,782	$ 62,805	$ 6,478
Net income (loss)	$ 31,547	$ 34,627	$ (18,810)	$ (90,980)
Total assets (at period end)	$ 283,500	$ 392,678	$ 393,315	$ 398,245
Total debt[(1)] (at period end)	$ 50,000	$ 104,000	$ 142,000	$ 133,000
Partners equity (at period end)	$ 190,875	$ 246,053	$ 211,445	$ 230,742

(1) As of December 31, 2011, PCEC had $74.0 million of borrowings under its senior secured credit agreement that is classified as short-term debt.

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Operating and Reserves Data of PCEC (Unaudited)

The following table provides the oil and natural gas sales volumes, average sales prices, average costs per Boe and capital expenditures for PCEC for the years ended December 31, 2011, 2010 and 2009 and reserves and production data for PCEC as of December 31, 2011, 2010 and 2009.

	Year Ended December 31,		
	2011	**2010**	**2009**
Operating Data:			
Sales volumes:			
Oil (MBbls)	1,171	1,086	1,240
Natural gas (MMcf)	264	259	305
Total sales (MBoe)	1,215	1,129	1,291
Average sales prices:			
Oil (per Bbl)	$ 90.41	$ 69.99	$ 53.22
Natural gas (per Mcf)	3.55	3.45	2.72
Average costs per Boe:			
Lease operating expenses	$ 29.82	$ 29.37	$ 27.02
Production and other taxes	2.56	2.08	2.92
Capital expenditures (in thousands):			
Property development costs	$ 29,901	$ 44,000	$ 15,852
Proved reserves (at period end):			
Proved developed (MBoe)	21,124	17,462	11,566
Proved undeveloped (MBoe)	13,004	1,847	1,276
Total proved reserves (MBoe)	34,128	19,309	12,842
Production (MBoe)	1,215	1,129	1,291

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Unaudited Pro Forma Distributable Income of the Trust

The table below outlines the calculation of pro forma distributable income from the Conveyed Interests for the year ended December 31, 2011 based on the excess of revenues over direct operating expenses attributable to the Conveyed Interests for the year ended December 31, 2011 as if the contemplated Formation Transactions had occurred on January 1, 2011. The table below should be read in conjunction with the unaudited pro forma financial information of the trust included elsewhere in this prospectus. The pro forma amounts below do not purport to present distributable income of the trust had the Formation Transactions contemplated actually occurred on January 1, 2011. Distributable income of the trust will be calculated using a modified cash basis of accounting. Please refer to the unaudited pro forma financial information for the trust included elsewhere in this prospectus for more information. As a result, you should view the amount of unaudited pro forma distributable income only as a general indication of the amount of cash available for distribution by the trust for the year ended December 31, 2011.

		Year Ended December 31, 2011 (In thousands, except per unit data) (Unaudited)
Oil and natural gas revenues	$	106,809
Direct operating expenses(1)		37,723
Excess of revenues over direct operating expenses	$	69,086
Development expenses		(29,901)
Excess of revenues over direct operating expenses and development expenses	$	39,185
Times Net Profits Interests(2)		80%
Income from Net Profits Interests		31,348
PCEC operating and services fee		(1,000)
Net payments to the trust	$	30,348
Pro forma adjustments:		
Trust general and administrative expenses		(850)
Cash available for distribution by the trust	$	29,498
Cash distribution per trust unit	$	

(1) Excludes expenses for regional operating management of $1,614 which are not included per the terms of the Net Profits Interests when calculating the distributable income to the trust.

(2) Includes no revenues or expenses attributable to the Remaining Properties.

Summary Projected Cash Distributions

The following table presents a calculation of forecasted cash distributions to holders of trust units who own the trust units as of the record date for the distribution payable in June 2012 and continue to own trust units through the record date for the distribution payable in May 2013 and was prepared by PCEC based on the assumptions that are described below and in Projected Cash Distributions Significant Assumptions Used to Prepare the Projected Cash Distributions. The trust expects to make its first distribution to unitholders in June 2012, which distribution will cover the proceeds attributable to the Conveyed Interests for April 2012.

PCEC does not as a matter of course make public projections as to future sales, earnings or other results. However, the management of PCEC has prepared the projected financial information set forth below to present the projected cash distributions to the holders of the trust units based on the estimates and hypothetical

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assumptions described below. The accompanying projected financial information was not prepared with a view toward complying with the published guidelines of the SEC or guidelines established by the American Institute of Certified Public Accountants with respect to projected financial information. More specifically, such information omits items that are not relevant to the trust. Neither PricewaterhouseCoopers LLP nor any other independent accountants have examined, compiled or performed any procedures with respect to the accompanying projected financial information and, accordingly, PricewaterhouseCoopers LLP does not express an opinion or any other form of assurance with respect thereto. The reports of PricewaterhouseCoopers LLP included in this prospectus relate to the trust, PCEC and PCEC s predecessor historical financial information. They do not extend to the projected financial information and should not be read to do so.

In the view of PCEC s management, the accompanying unaudited projected financial information was prepared on a reasonable basis and reflects the best currently available estimates and judgments of PCEC related to oil and natural gas production, operating expenses and development expenses, settlement of commodity derivative contracts and other general and administrative expenses based on:

- the oil and natural gas production estimates for the twelve months ending March 31, 2013 contained in the reserve reports;
- estimated direct operating expenses and development expenses for the twelve months ending March 31, 2013 contained in the reserve reports;
- projected payments made or received pursuant to the commodity derivative contracts for the twelve months ending March 31, 2013;
- estimated trust general and administrative expenses of $850,000 for the twelve months ending March 31, 2013; and
- an operating and services fee of $1,000,000 for the Underlying Properties payable to PCEC for the twelve months ending March 31, 2013.

The projected financial information was based on the hypothetical assumption that prices for crude oil and natural gas remain constant at $115.00 per Bbl of oil and $3.00 per MMBtu of natural gas during the twelve-month projection period. These assumed prices were based on Brent and Henry Hub futures strip pricing for the months of April 2012 through March 2013. Actual prices paid for oil and natural gas expected to be produced from the Underlying Properties during the twelve months ending March 31, 2013 will likely differ from these hypothetical prices due to fluctuations in the prices generally experienced with respect to the production of oil and natural gas and variations in basis differentials. For the twelve months ending March 31, 2013, the monthly average forward ICE crude oil (Brent) price per Bbl was approximately $117.96 and the monthly average forward NYMEX natural gas (Henry Hub) price per MMBtu was approximately $2.52.

Please read Projected Cash Distributions Significant Assumptions Used to Prepare the Projected Cash Distributions and 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 projections and estimates and the hypothetical assumptions on which they are based are subject to significant uncertainties, many of which are beyond the control of PCEC or the trust. Actual cash distributions to trust unitholders, therefore, could vary significantly based upon events or conditions occurring that are different from the events or conditions assumed to occur for purposes of these projections. Cash distributions to trust unitholders will be particularly sensitive to fluctuations in oil and natural gas prices. Please read 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. As a result of typical production declines for oil and natural gas properties, production estimates generally decrease from year to year, and the projected cash distributions shown in the table below are not necessarily indicative of distributions for future years. Please read Projected Cash Distributions

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Sensitivity of Projected Cash Distributions to Oil Production and Prices, which shows projected effects on cash distributions from hypothetical changes in oil production and prices. Because payments to the trust will be generated by depleting assets and the trust has a finite life with the production from the Underlying Properties diminishing over time, a portion of each distribution will represent, in effect, a return of your original investment. Please read Risk Factors 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, net profits interests 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 following table presents a calculation of forecasted cash distributions to holders of trust units for the twelve months ending May 31, 2013, which was prepared by PCEC based on the assumptions that are described in Projected Cash Distributions Significant Assumptions Used to Prepare the Projected Cash Distributions. The following table includes amounts associated with the Conveyed Interests for the projection period. The table does not include any amount for the Net Profits Interest for the Remaining Properties because the costs and development expenses associated with such properties exceed revenues associated with such properties for the projection period. Please read Computation of Net Profits and Royalties.

Projected Cash Distributions to Trust Unitholders	**12 Months Ending 5/31/13**
Developed Properties sales volumes, net to the trust[1]:	
Oil (MBbl)	1,025.2
Natural gas (MMcf)	256.1
Total Sales (MBoe)	1,067.8
Daily production (Boe)	2,925.6
Commodity prices[2]:	
Oil (per Bbl)	$ 115.00
Natural gas (per MMBtu)	$ 3.00
Assumed realized sales price[3]:	
Oil (per Bbl)	$ 107.39
Natural gas (per Mcf)	$ 2.51
Developed Properties net profits, net to the trust:	
Gross profits[4]:	
Oil sales	$ 110,096
Natural gas sales	643
Total sales	$ 110,739
Developed Properties costs, net to the trust[5]:	
Direct operating expenses[6]:	
Lease operating expenses	$ 30,365
Production and other taxes	3,589
Development expenses, net[7]	5,575
Settlement of commodity derivative contracts, net to the trust[8]	
Total	$ 39,529
Developed Properties Net Profits Interest	$ 71,210
Remaining Properties Royalty Interest[9]	91
PCEC operating and services fee[10]	(1,000)
Net payments to the trust	$ 70,301
Trust general and administrative expenses[11]	(850)
Cash available for distribution by the trust	$ 69,451

Cash distribution per trust unit (assumes units)

(1) Sales volumes net to the trust include 80% of sales volumes from the Developed Properties contained in the reserve report for the Underlying Properties.

(2) For a description of the effect of lower crude oil prices on projected cash distributions, please read Projected Cash Distributions Sensitivity of Projected Cash Distributions to Oil Production and Prices.

(3) Sales price net of forecasted gravity, quality, transportation, gathering and processing and marketing costs. For more information about the estimates and hypothetical assumptions made in preparing the table above, please read Projected Cash Distributions Significant Assumptions Used to Prepare the Projected Cash Distributions.

(4) Represents gross profits as described in Computation of Net Profits and Royalties Net Profits Interests.

(5) Costs net to the trust include 80% of costs from the Developed Properties contained in the reserve report for the Underlying Properties.

(6) Total direct operating expenses per Boe are projected to be $31.81.

(7) Total development expenses per Boe are projected to be $5.22.

(8) Reflects net cash impact of settlements of commodity derivative contracts relating to production. Please read The Underlying Properties Commodity Derivative Contracts.

(9) Represents the Royalty Interest as described in Computation of Net Profits and Royalties Royalty Interest.

(10) The PCEC operating and services fee relating to production from the Underlying Properties will be $1,000,000 on an annualized basis for the twelve months ending May 31, 2013 and will change on an annual basis commencing on April 1, 2013, based on changes to the United States Consumer Price Index, or CPI.

(11) Total general and administrative expenses of the trust on an annualized basis for the twelve months ending May 31, 2013 are expected to be $850,000 and will include the annual fees to the trustees, accounting fees, engineering fees, legal fees, printing costs and other expenses properly chargeable to the trust.

Pacific Coast Energy Company LP

PCEC is a privately held Delaware limited partnership formed on June 15, 2004 as BreitBurn Energy Company L.P. to engage in the production and development of oil and natural gas from properties located in California. As of December 31, 2011, PCEC held interests in approximately 276 gross (215 net) producing wells, and had proved reserves of approximately 34.1 MMBoe.

After giving pro forma effect to the conveyance of the Conveyed Interests to the trust, the offering of the trust units contemplated by this prospectus and the application of the net proceeds as described in Use of Proceeds, as of December 31, 2011, PCEC would have had total assets of $283.5 million and total liabilities of $92.6 million. For an explanation of the pro forma adjustments, please read Financial Statements of Pacific Coast Energy Company LP Unaudited Pro Forma Financial Statements Introduction.

The address of PCEC is 515 South Flower Street, Suite 4800, Los Angeles, California 90071, and its telephone number is (213) 225-5900.

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The Offering

Trust units offered by PCEC	trust units, or trust units if the underwriters exercise their option to purchase additional trust units in full
Trust units owned by PCEC after the offering	trust units, or trust units if the underwriters exercise their option to purchase additional trust units in full
Trust units outstanding after the offering	trust units
Use of proceeds	PCEC is offering all of the trust units to be sold in this offering, including the trust units to be sold upon any exercise of the underwriters option to purchase additional trust units. The estimated net proceeds of this offering to be received by PCEC will be approximately $ million, after deducting underwriting discounts and commissions, structuring fees and expenses, and $ million if the underwriters exercise their option to purchase additional trust units in full. PCEC intends to use the net proceeds from this offering, including any proceeds from the exercise of the underwriters option to purchase additional trust units, to repay amounts outstanding under its senior secured credit agreement and second lien credit agreement, to make a distribution of approximately $ million to the equity owners of PCEC and for general corporate purposes. PCEC is deemed to be an underwriter with respect to the trust units offered hereby. Please read Use of Proceeds.

Affiliates of Citigroup Global Markets Inc. (Citigroup) and Wells Fargo Securities, LLC (Wells Fargo), as holders of a beneficial interest in PCEC, will indirectly receive a portion of the proceeds from this offering in connection with the distribution to be made to the equity holders of PCEC. In addition, affiliates of certain of the underwriters participating in this offering are lenders under PCEC s senior secured credit agreement and second lien credit agreement and will receive a substantial portion of the proceeds from this offering pursuant to the repayment of a portion of the borrowings thereunder. Please read Underwriting Certain Relationships/FINRA Rules.

Proposed NYSE symbol	ROYT
Monthly cash distributions	The trust will pay monthly distributions to the holders of trust units as of the applicable record date (generally the last business day of each calendar month) on or before the 10th business day after the record date. The first distribution from the trust to the trust unitholders will be made on or about June 15, 2012 to trust unitholders owning trust units on or about May 31, 2012.
	Actual cash distributions to the trust unitholders will fluctuate 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

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natural gas and other factors. Because payments to the trust will be generated by depleting assets with the production from the Underlying Properties diminishing over time, a portion of each distribution will represent, in effect, a return of your original investment. Oil and natural gas production from proved reserves attributable to the Underlying Properties will decline over time. Please read Risk Factors.

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 will not reduce net profits calculated for the other. The amount of Royalty Interest Proceeds paid will be 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 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 future cumulative net profits for such properties exceed the cumulative total excess costs for such properties.

For any monthly period during which costs for the Remaining Properties exceed gross proceeds, the trust would be entitled to receive the Royalty Interest Proceeds. The trust would continue to receive payments associated with the Remaining Properties in the form of Royalty Interest Proceeds until the first day of the month following an NPI Payout. 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 2020. The trust would be entitled to receive the Royalty Interest Proceeds if, in any monthly period following an NPI Payout, costs for the Remaining Properties exceeded gross proceeds. Please read Computation of Net Profits and Royalties.

Dissolution of the trust	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 available for distribution to the trust 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.
Estimated ratio of taxable income to distributions	PCEC estimates that a trust unitholder who owns the trust units purchased in this offering through the record date for distributions for the month ending December 31, 2014, will recognize, on a cumulative basis, an amount of federal taxable income for that period of less than 40% of the cash distributed to such trust unitholder

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	with respect to that period. Please read United States Federal Income Tax Considerations Direct Taxation of Trust Unitholders for the basis of this estimate.
Summary of income tax consequences	Trust unitholders will be taxed directly on the income from assets of the trust. PCEC and the trust intend to treat the Conveyed Interests, which will be granted to the trust on a perpetual basis, as mineral royalty interests that generate ordinary income subject to depletion for U.S. federal income tax purposes. Please read United States Federal Income Tax Considerations.

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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.

Brent crude oil prices declined from record high levels in early July 2008 of over $145.00 per Bbl to below $35.00 per Bbl in December 2008. In March 2012, Brent crude oil prices ranged from $124.55 per Bbl to $127.97 per Bbl. Henry Hub natural gas prices declined from over $13.57 per MMBtu in July 2008 to below $2.00 per MMBtu in April 2012. In March 2012, Henry Hub natural gas prices ranged from $1.98 per MMBtu to $2.44 per MMBtu.

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

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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.

PCEC has entered into commodity derivative contracts with an affiliate of Wells Fargo in order to mitigate the effects of falling commodity prices through March 31, 2014. The trust will be entitled to the effect of 2,000 barrels of daily swap volumes of Brent crude oil at $115.00 per barrel during the twenty-four months ending March 31, 2014. The commodity derivative contracts are intended to reduce exposure of the revenues from oil production from the Underlying Properties to fluctuations in oil prices and to achieve more predictable cash flow. The commodity derivative contracts will limit the benefit to the trust of any increase in oil prices through March 31, 2014. The trust will be required to bear the settlement costs, if any, relating to the commodity derivatives contracts regardless of whether the corresponding quantities of oil are produced or sold. Furthermore, PCEC does not intend to enter into any commodity derivative contracts affecting the trust relating to oil volumes expected to be produced after March 31, 2014, and the terms of the conveyance of the Conveyed Interests will prohibit PCEC from entering into new hedging arrangements burdening the trust following the completion of this offering. As a result, the amount of the cash distributions will be subject to a greater fluctuation after March 31, 2014 due to changes in oil prices. For a discussion of the commodity derivative contracts, please read The Underlying Properties Commodity Derivative Contracts.

Estimates of future cash distributions to trust unitholders are based on assumptions that are inherently subjective.

The projected cash distributions to trust unitholders for the twelve months ending May 31, 2013 contained elsewhere in this prospectus are based on PCEC s calculations, and PCEC has not received an opinion or report on such calculations from any independent accountants or engineers. Such calculations are based on assumptions about drilling, production, crude oil and natural gas prices, hedging activities, development expenses, and other matters that are inherently uncertain and are subject to significant business, economic, financial, legal, regulatory and competitive risks and uncertainties that could cause actual results to differ materially from those estimated. In particular, these estimates have assumed that crude oil and natural gas production is sold in 2012 and 2013 based on assumed prices of $115.00 per Bbl in the case of crude oil and $3.00 per MMBtu in the case of natural gas. However, actual sales prices may be significantly lower. Additionally, these estimates assume the Underlying Properties will achieve production volumes set forth in the reserve reports; however, actual production volumes may be significantly lower. If prices or production are lower than expected, the amount of cash available for distribution to trust unitholders would be reduced.

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

The value of the trust units and the amount of future cash distributions to the trust unitholders will depend upon, among other things, the accuracy of the reserves and future production estimated to be attributable to the trust s interest in the Underlying Properties. Please read The Underlying Properties Reserve Reports for a discussion of the method of allocating proved reserves to the Underlying Properties and the Conveyed Interests. 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.

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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, estimated future distributions to trust unitholders may be reduced. 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, the estimated future distributions to trust unitholders may be reduced.

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The trust is passive in nature and neither the trust nor the trust unitholders will 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 to only receive cash distributions from the Conveyed Interests and commodity derivative contracts being conveyed to the trust. Trust unitholders have no voting rights with respect to PCEC and, therefore, will have no managerial, contractual or other ability to influence PCEC s activities or the operations of the Underlying Properties. PCEC operated approximately 98% of the average daily production from the Underlying Properties for the month ended December 31, 2011 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 will not be entitled to vote on any transfer or abandonment of the Underlying Properties, and the trust will not receive any profits from any such transfer. Please read The Underlying Properties Sale and Abandonment of Underlying Properties. 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 stand alone basis using the computation of net profits and royalties described in this prospectus. 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 has not identified for sale any of the Underlying Properties.

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.

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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, net profits interests 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 will provide that the trust s activities will be 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 will not be permitted to acquire other oil and natural gas properties, net profits interests 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 crude oil price differentials may adversely impact the cash distributions available to trust unitholders.

PCEC s crude oil production is sold in the local markets where the pricing is based on local or regional supply and demand factors. The prices that PCEC receives for its crude oil production have recently been higher than common benchmark prices, such as Brent. 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 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.

The amount of cash available for distribution by the trust will be 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 will indirectly bear 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 will 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

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by the trust in respect of a Net Profits Interest. Please read Computation of Net Profits and Royalties Net Profits Interests. 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 will be further reduced by the trust s general and administrative expenses, which are expected to be approximately $850,000 for the twelve months ending March 31, 2013, and by the PCEC operating and services fee, which will be $1,000,000 for the same period. The PCEC operating and services fee will change on an annual basis commencing on April 1, 2013, based on changes to the CPI. For details about the trust s general and administrative expenses and the PCEC operating and services fee, please read Description of the Trust Agreement Fees and Expenses.

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 a 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.

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

In 2011, 2010 and 2009, ConocoPhillips purchased 97% of PCEC s production and currently purchases 100% of its oil production. ConocoPhillips purchase of oil production from the Orcutt properties is pursuant to a long-term sales contract between ConocoPhillips and PCEC, and its purchase of oil production from the Sawtelle and West Pico properties is pursuant to a month-to-month contract. If ConocoPhillips 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.

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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. Production from PCEC s Diatomite properties averaged 673 Boe/d during December 2011.

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.

After the closing of the offering, PCEC will hold an aggregate of trust units, assuming no exercise of the underwriters option to purchase additional trust units. PCEC has agreed not to sell any trust units for a period of 180 days after the date of this prospectus unless Barclays Capital Inc. consents to a shorter period. Please read Underwriting. After such period, 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 or on any trading market that may develop. The trust has granted registration rights to PCEC, which, if exercised, would facilitate sales of trust units by PCEC.

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There has been no public market for the trust units, and accordingly the value after this offering may differ from the price in the offering.

The initial public offering price of the trust units will be determined by negotiation among PCEC and the underwriters. Among the factors to be considered in determining the number of trust units to be offered hereby and the initial public offering price will be estimates of distributions to trust unitholders; overall quality of the oil and natural gas properties attributable to the Underlying Properties; the history and prospects for the energy industry; PCEC s financial information; the prevailing securities markets at the time of this offering and the recent market prices of, and the demand for, publicly traded units of royalty trusts. None of PCEC, the trust or the underwriters will obtain any independent appraisal or other opinion of the value of the Conveyed Interests, other than the reserve reports prepared by Netherland Sewell.

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 will not owe any fiduciary duties or liabilities to the trust unitholders or the trust.

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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 will be 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 will 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 will not be 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 will be entitled to the same limitation of personal liability extended to stockholders of corporations for profit under the General Corporation Law of the State of Delaware. 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 wilderness, wetlands and other protected areas; and the imposition of substantial liabilities for pollution resulting from operations. For example, the U.S. Environmental Protection Agency, or EPA, has proposed regulations to 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. Any such 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 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 California Environmental Quality Act. 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 their 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 will indirectly bear 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,

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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 will be 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 our 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 is currently considering legislation that, if adopted in its proposed form, would subject companies involved in oil and natural gas exploration and production activities to, among other items, additional regulation of and restrictions on hydraulic fracturing of wells, the elimination of certain U.S. federal tax incentives and deductions available to oil and natural gas exploration and production activities and the prohibition or additional regulation of private energy commodity derivative and hedging activities. These and other potential regulations could increase the operating costs of 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 greenhouse gas, or GHG, emissions, namely carbon dioxide and methane, and future restrictions on such emissions could impact future operations on the Underlying

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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. During 2010, the EPA adopted two sets of rules regulating GHG emissions under the Clean Air Act, one of which requires a reduction in emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources under the Prevention of Significant Deterioration, or PSD, and Title V permitting programs. The stationary source rule tailors these permitting programs to apply to certain stationary sources in a multi-step process, with the largest sources first subject to permitting. Facilities required to obtain PSD permits for their GHG emissions also will be required to reduce those emissions according to best available control technology standards for GHGs that will be established by the states or, in some instances, by the EPA on a case-by-case basis. These EPA rulemakings 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. Reporting of GHG emissions from such facilities will be required on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011. 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 almost half 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. Since then, the California Air Resources Board, or CARB, has taken and plans to take various actions to implement the program, including the approval on December 11, 2008, of an AB32 Scoping Plan summarizing the main GHG-reduction strategies for California. In October 2011, the CARB adopted the final cap-and-trade regulation, including a delay in the start of the cap-and-trade rule s compliance obligations until 2013. The final cap-and-trade system is designed to be in conjunction with the Western Climate Initiative, which currently includes seven states and four Canadian provinces. 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.

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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 will be 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, and PCEC intends to use a portion of the net proceeds of this offering to repay indebtedness and for general corporate purposes instead of retaining all or a portion to pay costs for the operation and development of the Underlying Properties.

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. Please read Information about Pacific Coast Energy Company LP for additional information relating to PCEC, including information relating to the business of PCEC, historical financial statements of PCEC and other financial information relating to PCEC. PCEC will not be a reporting company following this offering and will not be required to file periodic reports with the SEC pursuant to the Securities Exchange Act of 1934, as amended, or the Exchange Act. Therefore, as a trust unitholder, you will not 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 will 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 Net Profits Interests were part of the bankruptcy estate, the trust may be treated as an unsecured creditor with respect to the Net Profits Interests.

PCEC and the trust believe that the Net Profits Interests 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 Net Profits Interests 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 Net Profits Interests constitute, for all purposes, an interest in real property, it is likely that a California court would hold that the Net Profits Interests 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 Net Profits Interests 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 Net Profits Interests 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

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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 will depend 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 will be 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.

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 trust 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. Please read State Tax Considerations.

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.

Among the items affected by President Obama s Budget Proposal for Fiscal Year 2012, or the Budget Proposal, are certain key U.S. federal income tax preferences relating to oil and natural gas exploration and production. Legislation has been proposed that includes proposals from the Budget Proposal that would, if enacted, materially revise certain tax preferences applicable to taxpayers engaged in the exploration or production of natural resources. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for United States production activities and (iv) the increase in the amortization period from two years to seven years for geophysical costs paid or incurred in connection with the exploration for, or development of, oil or gas within the United States. It is unclear whether any such changes will actually be enacted into law or, if enacted, how soon any such changes could become effective. The passage of any such legislation, or any other similar changes in U.S. federal income tax laws that eliminate certain tax preferences that are currently available with respect to oil and natural gas exploration and production, could reduce the cash available for distribution to the trust unitholders or adversely affect the value of the trust units.

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You will be required to pay taxes on your share of the trust s income even if you 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 will generate taxable income that could be different in amount than the cash the trust distributes, you will be required to pay any federal and applicable California income taxes and, in some cases, other state and local income taxes on your share of the trust s taxable income even if you receive no cash distributions from the trust. You may not receive cash distributions from the trust equal to your 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 you sell your trust units, you will recognize a gain or loss equal to the difference between the amount realized and your 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. Please read United States Federal Income Tax Considerations Tax Consequences to U.S. Trust Unitholders Disposition of Trust Units.

The trust will allocate 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 will generally allocate 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. Please read United States Federal Income Tax Considerations Direct Taxation of Trust Unitholders.

As a result of investing in trust units, you 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 will likely be 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.

PCEC has received 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 for withholding, and will use its commercially reasonable efforts to maintain such waiver, including by seeking a renewal of such waiver prior to its expiration under California law. There can be no assurances, however, that PCEC will be able to obtain such a waiver in the future and, in such a case, PCEC may be required to withhold such amounts.

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FORWARD-LOOKING STATEMENTS

This prospectus contains forward-looking statements about PCEC and the trust that are subject to risks and uncertainties. All statements other than statements of historical fact included in this prospectus, including, without limitation, statements under Prospectus Summary 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 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. Forward-looking statements are subject to risks and uncertainties and include statements made in this prospectus under Projected Cash Distributions, statements pertaining to future development activities and costs, and other statements in this prospectus that are prospective and constitute forward-looking statements.

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 prospectus, 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 in 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 prospectus. Neither PCEC nor the trust undertakes any obligation to release publicly any revisions to the forward-looking statements to reflect events or circumstances after the date of this prospectus or to reflect the occurrence of unanticipated events, unless the securities laws require it to do so.

This prospectus describes other important factors that could cause actual results to differ materially from expectations of PCEC and the trust, including under the heading Risk Factors. All written and oral forward-looking statements attributable to PCEC, the trust, or persons acting on behalf of PCEC or the trust are expressly qualified in their entirety by such factors.

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USE OF PROCEEDS

PCEC is offering all of the trust units to be sold in this offering, including the trust units to be sold upon the exercise of the underwriters option to purchase additional trust units. PCEC expects to receive net proceeds from the sale of trust units offered by this prospectus of approximately $ million, after deducting underwriting discounts and commissions, structuring fees and offering expenses, and an additional $ million if the underwriters exercise their option to purchase additional trust units in full. PCEC is deemed to be an underwriter with respect to the trust units offered hereby.

PCEC intends to use the net proceeds from this offering, including any proceeds from the exercise of the underwriters option to purchase additional trust units, to repay borrowings outstanding under its senior secured credit agreement and second lien credit agreement, to make a distribution to the equity owners of PCEC and for general corporate purposes. Affiliates of Citigroup and Wells Fargo, as holders of a beneficial interest in PCEC, will indirectly receive a portion of the proceeds from this offering in connection with the distribution to be made to the equity holders of PCEC. Please read Underwriting Certain Relationships/FINRA Rules. The table below sets forth these intended uses with the corresponding dollar amounts planned for such use, assuming no exercise of the underwriters over-allotment option.

Intended Use	**Intended Amount Dedicated to Such Use (in millions)**
Repay borrowings outstanding under PCEC s senior secured credit agreement and second lien credit agreement	$
Distribution to equity owners of PCEC	$
General corporate purposes	$

PCEC maintains a $400 million senior secured credit agreement, which provides for revolving loans and a $60 million second lien term loan. Borrowings under the senior secured credit agreement have a maturity date of August 24, 2012 and bear interest at the applicable LIBOR rate, plus applicable margins ranging from 1.50% to 2.25%, or at a base rate, based upon the greatest of (a) the rate of interest as publicly announced by the administrative agent as its reference rate and (b) the federal funds rate plus 0.50%, plus applicable margins ranging from 0.50% to 1.25%. Borrowings under the second lien term loan have a maturity date of February 24, 2013 and bear interest at either (a) the greater of (i) the applicable LIBOR rate and (ii) 3.25%, plus the applicable margin of 6.50%, or (b) a base rate, based upon the greater of (i) the rate of interest as publicly announced by the administrative agent as its reference rate and (ii) the federal funds rate plus 0.50%, plus the applicable margin of 5.50%.

As of December 31, 2011, total borrowings under PCEC s senior secured credit agreement were $74.0 million at a weighted average interest rate of approximately 2.01% for the fourth quarter of 2011. As of December 31, 2011, PCEC had $30.0 million outstanding under its second lien term loan at a weighted average interest rate of approximately 8.75% for the fourth quarter of 2011. Affiliates of certain of the underwriters participating in this offering are lenders under PCEC s senior secured credit agreement and second lien credit agreement and will receive a substantial portion of the proceeds from this offering pursuant to the repayment of a portion of the borrowings thereunder. Please read Underwriting Certain Relationships/FINRA Rules.

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PACIFIC COAST ENERGY COMPANY LP

PCEC is a privately held Delaware limited partnership formed on June 15, 2004 as BreitBurn Energy Company L.P. to engage in the production and development of oil and natural gas from properties located in California.

The Underlying Properties were acquired through various transactions prior to 2005 and are located in the Santa Maria and Los Angeles Basins in California. After giving pro forma effect to the conveyance of the Conveyed Interests to the trust, the offering of the trust units contemplated by this prospectus and the application of the net proceeds as described in Use of Proceeds, as of December 31, 2011, PCEC would have had total assets of $283.5 million and total liabilities of $92.6 million. For an explanation of the pro forma adjustments, please read Financial Statements of Pacific Coast Energy Company LP Unaudited Pro Forma Financial Statements Introduction.

As of December 31, 2011, PCEC held interests in approximately 276 gross (215 net) producing wells, and had proved reserves of approximately 34.1 MBoe.

The trust units do not represent interests in, or obligations of, PCEC.

Selected Historical and Unaudited Pro Forma Financial Data of PCEC

The selected historical audited financial data of PCEC as of December 31, 2011 and 2010 and for the years in the three-year period ended December 31, 2011 and the period from August 26, 2008 to December 31, 2008 have been derived from PCEC s audited financial statements. The selected historical audited financial data for the period from January 1, 2008 to August 25, 2008 and for the year ended December 31, 2007 have been derived from PCEC s predecessor s audited financial statements.

The selected unaudited pro forma financial data as of and for the year ended December 31, 2011 has been derived from the unaudited pro forma financial statements of PCEC included elsewhere in this prospectus. The pro forma data has been prepared as if the conveyance of the Conveyed Interests and the offer and sale of the trust units and application of the net proceeds therefrom had taken place (i) on December 31, 2011, in the case of pro forma balance sheet information as of December 31, 2011, and (ii) as of January 1, 2011, in the case of pro forma statement of earnings for the year ended December 31, 2011. The selected historical and unaudited pro forma financial data presented below should be read in conjunction with Information About Pacific Coast Energy Company LP Management s Discussion and Analysis of Financial Condition and Results of Operations of PCEC and the accompanying financial statements and related notes of PCEC included elsewhere in this prospectus.

	PCEC Pro Forma for the Offering (Including the Conveyance of the Conveyed Interests)	PCEC				Predecessor	
		Year Ended December 31,			August 26 to December 31,	January 1 to August 25,	Year Ended December 31,
	Year Ended December 31, 2011	2011	2010	2009	2008	2008	2007
(In thousands)	(Unaudited)						
Revenues	$ 97,004	$ 110,782	$ 62,805	$ 6,478	$ 166,934	$ 61,472	$ 47,435
Net income (loss)	$ 31,547	$ 34,627	$ (18,810)	$ (90,980)	$ 135,842	$ 25,063	$ 2,469
Total assets (at period end)	$ 283,500	$ 392,678	$ 393,315	$ 398,245	$ 509,405	$ 221,675	$ 212,473
Total debt[(1)] (at period end)	$ 50,000	$ 104,000	$ 142,000	$ 133,000	$ 155,500	$ 13,500	$ 9,500
Partners equity	$ 190,875	$ 246,053	$ 211,445	$ 230,742	$ 322,125	$ 171,726	$ 146,665

(1) As of December 31, 2011, PCEC had $74.0 million of borrowings under its senior secured credit agreement that is classified as short-term debt.

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Management of PCEC

PCEC has no employees, executive officers or directors, and is managed by its general partner, PCEC (GP) LLC, or PCEC GP, the executive officers of which are employees of BreitBurn Management Company LLC, or BreitBurn Management. PCEC GP is managed by the Board of Representatives of Pacific Coast Energy Holdings LLC, or PCEH, the sole member of PCEC GP. Set forth in the table below are the names, ages and titles of the Board of Representatives of PCEH and the executive officers of PCEC GP. In August 2008, PCEH acquired its interest in PCEC by acquiring PCEC s general and limited partners.

Name	Age	Title
Randall H. Breitenbach	51	Chief Executive Officer and Board Representative
Halbert S. Washburn	52	President and Board Representative
Mark L. Pease	55	Executive Vice President and Chief Operating Officer
James G. Jackson	47	Executive Vice President and Chief Financial Officer
Gregory C. Brown	60	Executive Vice President and General Counsel
Chris E. Williamson	54	Vice President Operations
W. Jackson Washburn	49	Vice President Real Estate
Bruce D. McFarland	55	Treasurer and Secretary
Lawrence C. Smith	58	Controller
Howard Hoffen	48	Board Representative
Gregory D. Myers	41	Board Representative
V. Frank Pottow	48	Board Representative

Randall H. Breitenbach is a co-founder of PCEC and has been PCEH s Chief Executive Officer since August 2008 and is a member and the Chairman of the Board of Representatives of PCEH, the sole member of PCEC GP. He also served as the Co-Chief Executive Officer of PCEH from August 2008 until March 2012 and as the Co-Chief Executive Officer of BreitBurn GP, LLC, or BreitBurn GP, which is the General Partner of BreitBurn Energy Partners L.P., a publicly traded oil and gas partnership, since March 2006. In addition, Mr. Breitenbach has been the President of BreitBurn GP since April 2010 and from March 2006 until April 2010, he served as Co-Chief Executive Officer and a Director of BreitBurn GP. In December, 2011, he was re-appointed to the Board of BreitBurn GP. Mr. Breitenbach currently serves as a Trustee and is Chairman of the governance and nominating committee for Hotchkis and Wiley Funds, which is a mutual funds company. He has also served as a board member, including Chairman of the Board of Directors, of the Stanford University Petroleum Investments Committee. Mr. Breitenbach holds both a B.S and M.S. degree in Petroleum Engineering from Stanford University and an M.B.A. from Harvard Business School.

Mr. Breitenbach has a distinguished career as an executive in the oil and gas industry. His more than 25 years of management experience in the oil and gas industry provides Mr. Breitenbach with a keen understanding of PCEC s operations and an in-depth knowledge of its industry. Mr. Breitenbach s experience serving on boards of directors of both public and private companies allows him to provide PCEH s Board of Representatives with a variety of perspectives on corporate governance and other issues.

Halbert S. Washburn is a co-founder of PCEC and has been PCEH s President since March 2012 and is a member of the Board of Representatives of PCEH, the sole member of PCEC GP. In addition, Mr. Washburn has been the Chief Executive Officer of BreitBurn GP since April 2010. He served as Co-Chief Executive Officer and a Director of BreitBurn GP from March 2006 until April 2010 and was the Chairman of the Board from July 2008 to April 2010. In December 2011, he was re-appointed to the Board of BreitBurn GP. Mr. Washburn is the brother of W. Jackson Washburn, PCEH s Vice President Real Estate. Since December 2005, Mr. Washburn has served as a member of the Board of Directors and the audit and compensation committees of Rentech, Inc., a publicly traded alternative fuels company, and since June 2011, has served as the Chairman of the Rentech, Inc. Board. Since July 2011, Mr. Washburn has also served as a Director of Rentech Nitrogen GP, LLC, the general partner of Rentech Nitrogen Partners, L.P., a publicly traded limited partnership involved in the production of

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nitrogen fertilizer. He has been a member of the California Independent Petroleum Association since 1995 and served as Chairman of the executive committee of the Board of Directors from 2008 to 2010. He has also served as a board member, including Chairman of the Board of Directors, of the Stanford University Petroleum Investments Committee. Mr. Washburn holds a B.S. degree in Petroleum Engineering from Stanford University.

Mr. Washburn has a distinguished career as an executive in the oil and gas industry. His more than 25 years of management experience in the oil and gas industry provides Mr. Washburn with a keen understanding of PCEC s operations and an in-depth knowledge of its industry. Mr. Washburn s experience serving on boards of directors of both public and private companies allows him to provide PCEH s Board of Representatives with a variety of perspectives on corporate governance and other issues.

Mark L. Pease has been PCEH s Chief Operating Officer since August 2008. Mr. Pease has been the Chief Operating Officer and an Executive Vice President of BreitBurn GP since December 2007. Prior to joining BreitBurn GP, Mr. Pease served as Senior Vice President, E&P Technology & Services for Anadarko Petroleum Corporation, an international and domestic oil and natural gas exploration and production company, or Anadarko. Mr. Pease joined Anadarko in 1979 as an engineer, and served as Senior Vice President, North America from 2004 to 2006 and as Vice President, U.S. Onshore and Offshore from 2002 to 2004. Mr. Pease obtained a B.S. in Petroleum Engineering from the Colorado School of Mines.

James G. Jackson has been PCEH s Chief Financial Officer since August 2008. Mr. Jackson has also served as the Chief Financial Officer of BreitBurn GP since July 2006 and as an Executive Vice President since October 2007. Since June 2011, Mr. Jackson has served as a member of the Board of Directors of Niska Gas Storage Partners LLC, a publicly traded master limited partnership that owns and operates natural gas storage assets in North America. Before joining BreitBurn GP, Mr. Jackson served as Managing Director of the Global Markets and Investment Banking Group for Merrill Lynch & Co., a global financial management and investment banking firm. Mr. Jackson joined Merrill Lynch in 1992 and was elected Managing Director in 2001. Previously, Mr. Jackson was a Financial Analyst with Morgan Stanley & Co. from 1986 to 1989 and was an Associate in the Mergers and Acquisitions Group of the Long-Term Credit Bank of Japan from 1989 to 1990. Mr. Jackson obtained a B.S. in Business Administration from Georgetown University and an M.B.A. from the Stanford Graduate School of Business.

Gregory C. Brown has been PCEH s General Counsel and an Executive Vice President since August 2008. Mr. Brown joined BreitBurn GP in December 2006 and currently serves as its General Counsel and Executive Vice President. Before joining BreitBurn GP, Mr. Brown was a partner at Bright and Brown, a law firm specializing in energy and environmental law that he co-founded in 1981. Mr. Brown earned a B.A. degree from George Washington University, with Honors, Phi Beta Kappa, and a J.D. from the University of California, Los Angeles. Mr. Brown was Mayor and has served on the City Council of the City of La Canada Flintridge from 2003 to 2011.

Chris E. Williamson has been PCEH s Vice President of Operations since August 2008. Mr. Williamson has also served as a Senior Vice President of BreitBurn GP since January 2008 and previously served as Vice President of Operations since March 2006. Before joining BreitBurn GP, Mr. Williamson worked for five years as a petroleum engineer for Macpherson Oil Company. Prior to his position with Macpherson, Mr. Williamson worked at Shell Oil Company for eight years holding various positions in Engineering and Operations. Mr. Williamson holds a B.S. in Chemical Engineering from Purdue University.

W. Jackson Washburn has been PCEH s Vice President of Real Estate since August 2008. Mr. Washburn has served as the Senior Vice President Business Development of BreitBurn GP since April 2009 and previously served as Vice President Business Development since August 2007. Mr. Washburn is the brother of Halbert S. Washburn, PCEH s President. Since joining PCEC s predecessor in 1992, Mr. Washburn has served in a variety of capacities, and has served as President of PCEC Land Company, LLC, a subsidiary of PCEC, since 2000. Mr. Washburn obtained a B.A. in Psychology from Wake Forest University.

Bruce D. McFarland has been PCEH s Treasurer since August 2008. Mr. McFarland has served as the Vice President and Treasurer of BreitBurn GP since March 2006 and as a Vice President since April 2009. Mr. McFarland previously served as the Chief Financial Officer of BreitBurn GP from March 2006 through June 2006. Since joining PCEC s predecessor in 1994, Mr. McFarland served as Controller and Treasurer for more than five years. Before joining PCEC s predecessor, Mr. McFarland served as Division Controller of IT Corporation and worked at PriceWaterhouseCoopers as a Certified Public Accountant. Mr. McFarland obtained a B.S. in Civil Engineering from the University of Florida and an M.B.A. from the University of California, Los Angeles.

Lawrence C. Smith has been PCEH s Controller since August 2008. Mr. Smith has also served as the Controller of BreitBurn GP since June 2006 and as a Vice President since April 2009. Before joining BreitBurn GP, Mr. Smith served as the Corporate Accounting Compliance and Implementation Manager of Unocal Corporation, which was an oil and natural gas production and exploration development company, or Unocal, from 2000 through May 2006. Mr. Smith worked at Unocal from 1981 through May 2006 and held various managerial positions in Unocal s accounting and finance organizations. Mr. Smith obtained a B.B.A. in Accounting from the University of Houston, an M.B.A. from the University of California, Los Angeles, and is a Certified Public Accountant.

Howard Hoffen has been a member of the Board of Representatives of PCEH since August 2008. Mr. Hoffen has been the Chairman and Chief Executive Officer of Metalmark Capital LLC, or Metalmark, since its formation in 2004. Prior to joining Metalmark, from 2001 to 2004, he was the Chairman and CEO of Morgan Stanley Capital Partners and a Managing Director of Morgan Stanley & Co., since 1997. Additionally, Mr. Hoffen serves as a Director of EnerSys, Union Drilling and several private companies. Mr. Hoffen received a B.S. from Columbia University and an M.B.A from Harvard Business School.

PCEC believes that Mr. Hoffen s many years of investing experience, as well as his in-depth knowledge of the oil and gas industry generally, and PCEC in particular, provide him with the necessary skills to be a member of the Board of Representatives of PCEH.

Gregory D. Myers has been a member of the Board of Representatives of PCEH since August 2008. Mr. Myers is a Managing Director at Metalmark and was a founding member in 2004. From 1998 to 2004, Mr. Myers was a senior investment professional at Morgan Stanley Capital Partners. Mr. Myers also serves as a Director of Union Drilling and several private companies. Mr. Myers received a B.S. and B.A. from The University of Pennsylvania and an M.B.A. from Harvard Business School.

PCEC believes that Mr. Myers many years of investing experience, as well as his in-depth knowledge of the oil and gas industry generally, and PCEC in particular, provide him with the necessary skills to be a member of the Board of Representatives of PCEH.

V. Frank Pottow has been a member of the Board of Representatives of PCEH since August 2008. Since 2009, Mr. Pottow has been a Managing Director and co-founder of GCP Capital Partners, LLC. From 2002 to 2009 Mr. Pottow was a Managing Director and member of the investment committee of Greenhill Capital Partners, LLC, the global merchant banking business of Greenhill & Co., Inc. From 1997 to 2002, he was a co-founder and Managing Director of SG Capital Partners. Additionally, Mr. Pottow was a Principal of Odyssey Partners, L.P. from 1992 to 1996. Mr. Pottow also serves as a board member of several private companies. Mr. Pottow obtained a B.S. from The Wharton School of The University of Pennsylvania and received an M.B.A. from Harvard Business School.

PCEC believes that Mr. Pottow s many years of investing experience, as well as his in-depth knowledge of the oil and gas industry generally, and PCEC in particular, provide him with the necessary skills to be a member of the Board of Representatives of PCEH.

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Beneficial Ownership of PCEC

The following table sets forth, as of March 1, 2011, the beneficial ownership of limited partner interests of PCEC held by:

- each person who beneficially owns 5% or more of the outstanding limited partner interests in PCEC;
- each named executive officer of PCEC GP and member of the Board of Representatives of PCEH; and
- all executive officers of PCEC GP and members of the Board of Representatives of PCEH as a group.

Except as indicated by footnote, the persons named in the table below have sole voting and investment power with respect to all limited partner interests of PCEC shown as beneficially owned by them and their address is 515 South Flower Street, Suite 4800, Los Angeles, California 90071.

Name of Beneficial Owner	Percentage of Limited Partner Interests Beneficially Owned
PCEC (LP) LLC[(1)]	100%
Halbert S. Washburn	
Randall H. Breitenbach	
Mark L. Pease	
James G. Jackson	
Gregory C. Brown	
Howard Hoffen	
Gregory D. Myers	
V. Frank Pottow	
Board Representatives and executive officers of PCEC GP as a group (12 persons)	

(1) PCEC (LP) LLC is wholly owned by PCEH, which is owned by Metalmark BreitBurn Holdings LLC, or Metalmark Breitburn, Greenhill Capital Partners II, L.P. and its affiliated investment limited partnerships, and certain other investors and members of PCEC GP s senior management. As of March 1, 2012, the beneficial ownership of limited liability company interests of PCEH is as follows:

Name of Beneficial Owner	Percentage of Membership Interests Beneficially Owned
Metalmark BreitBurn Holdings LLC[(a)]	51.2%
Greenhill Capital Partners II, L.P.[(b)]	19.8%
Greenhill Capital Partners (Employees) II, L.P.[(b)]	9.5%
Greenhill Capital Partners (Cayman) II, L.P.[(b)]	7.8%
Greenhill Capital Partners (Executives) II, L.P.[(b)]	1.4%
BreitBurn Energy Corporation[(c)]	6.5%
Halbert S. Washburn[(d)]	6.5%

Randall H. Breitenbach[d]	6.5%
Mark L. Pease	0.2%
James G. Jackson	0.3%
Gregory C. Brown	0.2%
Board Representatives and executive officers of PCEC GP as a group (12 persons)	7.8%

(a) The limited liability company interests of Metalmark BreitBurn are owned by the following six affiliated private equity funds: Metalmark Capital Partners (C) II, L.P.; Metalmark Capital Partners II Co-Investment, L.P.; Metalmark Capital Partners II, L.P.; MCP II (TE) AIF, L.P.; MCP II (Cayman) AIF, L.P.; and

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Metalmark Capital Partners II Executive Fund, L.P., which are collectively referred to as the Metalmark Funds. Metalmark Capital Partners II GP, L.P. is the managing general partner of each of the Metalmark Funds and has voting control over their limited liability company interests in Metalmark Breitburn. Investment decisions on behalf of the Metalmark Funds, including with respect to their limited liability company interests in Metalmark Breitburn and their indirect interests in PCEH, are made by the team of investment professionals responsible for the management of the Metalmark Funds. Metalmark Capital Holdings LLC, an indirect subsidiary of Citibank, N.A., is the general partner of Metalmark Capital Partners II GP, L.P. The principal business address of Metalmark BreitBurn and each of the Metalmark Funds is 1177 Avenue of the Americas, 40th Floor, New York, NY 10036.

(b) Greenhill Capital Partners II, L.P., Greenhill Capital Partners (Cayman) II, L.P., Greenhill Capital Partners (Executives) II, L.P. and Greenhill Capital Partners (Employees) II L.P. are collectively referred to as the Greenhill Funds. GCP Managing Partner II, L.P., the general partner of each of the Greenhill Funds, as well as Greenhill Capital Partners, LLC, which controls the general partner, and Greenhill & Co., Inc., the sole member of Greenhill Capital Partners, LLC, may be deemed to beneficially own the limited liability company interests of PCEH held by the Greenhill Funds. PCEC has been advised by the Greenhill Funds that all decisions regarding investments by the Greenhill Funds, including with respect to their limited liability company interests in PCEH, are made by an investment committee whose composition may change from time to time. The current members of the investment committee are Robert Niehaus, Frank Pottow, Boris Gutin, Robert Deutsch, Robert Greenhill and Scott Bok. No individual has authority to make any such decisions without the approval of the investment committee. Each member of the investment committee disclaims beneficial ownership in the interests held by the Greenhill Funds except to the extent of his pecuniary interest therein. The principal address of each of the Greenhill Funds, Greenhill Capital Partners, LLC, GCP Managing Partner II, L.P. and Greenhill & Co., Inc. is 300 Park Avenue, New York, NY 10022.

(c) Messrs. Washburn and Breitenbach collectively own 100% of the outstanding shares of BreitBurn Energy Corporation.

(d) Includes interests beneficially owned by BreitBurn Energy Corporation.

Beneficial Ownership of Pacific Coast Oil Trust

The following table sets forth the beneficial ownership of trust units of the trust that will be outstanding after giving effect to the consummation of this offering, assuming no exercise of the underwriters option to purchase additional trust units, and held, directly or indirectly, by each person who will then beneficially own 5% or more of the outstanding trust units.

Name of Beneficial Owner	Class of Securities	Percentage of Ownership
PCEC	Trust Units	%

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CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

Registration Rights Agreement

The trust will enter into a registration rights agreement with PCEC in connection with PCEC s contribution to the trust of the Conveyed Interests. Under the registration rights agreement, the trust will agree, for the benefit of PCEC and any transferee of PCEC s trust units, to register the trust units they hold. In connection with the preparation and filing of any registration statement, 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. Please read Trust Units Eligible for Future Sale Registration Rights.

Operating and Services Agreement

In connection with the closing of this offering, the trust will enter into an operating and services agreement with PCEC pursuant to which PCEC will provide the trust with certain operating and informational services relating to the Conveyed Interests in exchange for a monthly fee. The PCEC operating and services fee will be charged monthly in an amount equal to $83,333.33, which fee will change on an annual basis commencing on April 1, 2013, based on changes to the CPI. 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.

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THE TRUST

The trust is a statutory trust created under the Delaware Statutory Trust Act on January 3, 2012. The business and affairs of the trust will be managed by The Bank of New York Mellon Trust Company, N.A., as trustee. However, 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. PCEC has no ability to manage or influence the operations of the trust. In addition, Wilmington Trust, National Association will act as Delaware trustee of the trust. The Delaware trustee will have only minimal duties as are necessary to satisfy the requirement of the Delaware Statutory Trust Act that the trust have at least one trustee who has its principal place of business in Delaware. In connection with the closing of this offering, PCEC will contribute the Conveyed Interests to the trust in exchange for newly issued trust units. PCEC will make its first payment to the trust pursuant to the Conveyed Interests in June 2012.

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. The trustee may also deposit funds awaiting distribution in an account with itself, which may be non-interest bearing, and make other short-term investments with the funds distributed to the trust. The trustee has no current plans to authorize the trust to borrow money.

The trust will pay the trustee and Delaware trustee an administrative fee of $200,000 and $2,000 per year, respectively. The trust will also incur legal, accounting, tax, advisory and engineering fees, printing costs and other administrative and out-of-pocket expenses that are deducted by the trust before distributions are made to trust unitholders, including the monthly PCEC operating and services fee described below. The trust will also be responsible for paying other expenses incurred as a result of being a publicly traded entity, including costs associated with annual, quarterly and monthly reports to trust unitholders, tax return and Form 1099 preparation and distribution, NYSE listing fees, independent auditor fees and registrar and transfer agent fees.

In connection with the closing of this offering, the trust will enter into an operating and services agreement with PCEC pursuant to which PCEC will provide the trust with certain operating and informational services relating to the Conveyed Interests in exchange for a monthly fee. Please read Certain Relationships and Related Party Transactions Operating and Services Agreement. The trust s general and administrative expenses are expected to be $850,000 for the twelve months ending March 31, 2013. The PCEC operating and services fee will be $1,000,000 for the twelve months ending March 31, 2013. The PCEC operating and services fee will change on an annual basis commencing on April 1, 2013, based on changes to the CPI.

The trust will dissolve upon the earliest to occur of the following: (1) the trust, upon the approval of the holders of at least 75% of the outstanding trust units, sells the Conveyed Interests, (2) the annual cash available for distribution to the trust 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.

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PROJECTED CASH DISTRIBUTIONS

Immediately prior to the closing of this offering, PCEC will create the Conveyed Interests through a conveyance to the trust of net profits interests and royalties carved from PCEC s interests in the Underlying Properties located in California. The Conveyed Interests entitle the trust to receive 80% of the net profits from the sale of oil and natural gas production from the Developed Properties and either a 7.5% royalty interest from the sale of oil and natural gas production from the portion of 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. 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 amounts associated with the Remaining Properties in the form of Royalty Interest Proceeds until the NPI Payout occurs in approximately 2020. Please read Computation of Net Profits and Royalties.

The amount of trust revenues and cash distributions to trust unitholders will depend on, among other things:

- oil and natural gas sales prices;
- the volume of oil and natural gas produced and sold attributable to the Underlying Properties;
- the payments made or received by PCEC pursuant to any commodity derivative contracts;
- direct operating expenses;
- development expenses; and
- administrative expenses of the trust.

PCEC does not as a matter of course make public projections as to future sales, earnings or other results. However, the management of PCEC has prepared the projected financial information set forth below to present the projected cash distributions to the holders of the trust units based on the estimates and hypothetical assumptions described below. The accompanying projected financial information was not prepared with a view toward complying with the published guidelines of the SEC or guidelines established by the American Institute of Certified Public Accountants with respect to projected financial information. More specifically, such information omits items that are not relevant to the trust.

In the view of PCEC s management, the accompanying unaudited projected financial information was prepared on a reasonable basis and reflects the best currently available estimates and judgments of PCEC related to oil and natural gas production, operating expenses and development expenses, settlement of commodity derivative contracts and other general and administrative expenses based on:

- the oil and natural gas production estimates for the twelve months ending March 31, 2013 contained in the reserve reports;
- estimated direct operating expenses and development expenses for the twelve months ending March 31, 2013 contained in the reserve reports;
- projected payments made or received pursuant to the commodity derivative contracts for the twelve months ending March 31, 2013;

estimated trust general and administrative expenses of $850,000 for the twelve months ending March 31, 2013; and

an operating and services fee of $1,000,000 payable to PCEC for the twelve months ending March 31, 2013.

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The projected financial information was based on the hypothetical assumption that prices for crude oil and natural gas remain constant at $115.00 per Bbl of oil and $3.00 per MMBtu of natural gas during the twelve-month projection period. These assumed prices were based on Brent and Henry Hub futures strip pricing for the months of April 2012 through March 2013. Actual prices paid for oil and natural gas expected to be produced from the Underlying Properties during the twelve months ending March 31, 2013 will likely differ from these hypothetical prices due to fluctuations in the prices generally experienced with respect to the production of oil and natural gas and variations in basis differentials. For the twelve months ending March 31, 2013, the monthly average forward ICE crude oil (Brent) price per Bbl was approximately $117.96 and the monthly average forward NYMEX natural gas (Henry Hub) price per MMBtu was approximately $2.52.

Please read Significant Assumptions Used to Prepare the Projected Cash Distributions and 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.

Neither PricewaterhouseCoopers LLP nor any other independent accountant has examined, compiled or performed any procedures with respect to the accompanying projected financial information and, accordingly, PricewaterhouseCoopers LLP does not express an opinion or any other form of assurance with respect thereto. The reports of PricewaterhouseCoopers LLP included in this prospectus relate to the trust, PCEC and PCEC s predecessor historical financial information. They do not extend to the projected financial information and should not be read to do so.

The projections and estimates and the hypothetical assumptions on which they are based are subject to significant uncertainties, many of which are beyond the control of PCEC or the trust. Actual cash distributions to trust unitholders, therefore, could vary significantly based upon events or conditions occurring that are different from the events or conditions assumed to occur for purposes of these projections. Cash distributions to trust unitholders will be particularly sensitive to fluctuations in oil and natural gas prices. Please read 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. As a result of typical production declines for oil and natural gas properties, production estimates generally decrease from year to year, and the projected cash distributions shown in the table below are not necessarily indicative of distributions for future years. Please read Sensitivity of Projected Cash Distributions to Oil Production and Prices below, which shows projected effects on cash distributions from hypothetical changes in oil production and prices. Because payments to the trust will be generated by depleting assets and the trust has a finite life with the production from the Underlying Properties diminishing over time, a portion of each distribution will represent, in effect, a return of your original investment. Please read Risk Factors 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, net profits interests 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. Further, actual sales volumes, net profits and costs for each month may vary significantly based upon events or conditions occurring that are different from those assumed to occur for each projected month. Any changes in these projected amounts would result in a change in the cash distributions to unitholders.

The following table presents a calculation of forecasted cash distributions to holders of trust units for each of the twelve months ending May 31, 2013, which was prepared by PCEC based on the assumptions that are described below in Significant Assumptions Used to Prepare the Projected Cash Distributions. The following table includes amounts associated with the Conveyed Interests for the projection period. The table does not include any amount for the Net Profits Interest for the Remaining Properties because the costs and development expenses associated with such properties exceed revenues associated with such properties for the projection period. Please read Computation of Net Profits and Royalties.

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Projected Cash Distributions to Trust Unitholders	**Projections for the Month Ending**					
	6/30/12	**7/31/12**	**8/31/12**	**9/30/12**	**10/31/12**	**11/30/12**
Developed Properties sales volumes, net to the trust[1]:						
Oil (MBbl)	85.9	88.0	84.6	86.8	86.3	83.6
Natural gas (MMcf)	21.4	21.8	21.6	22.1	21.9	21.4
Total Sales (MBoe)	89.4	91.7	88.2	90.5	90.0	87.2
Daily production (Boe)	2,981.2	2,956.7	2,939.6	2,918.5	2,901.8	2,905.2
Commodity prices[2]:						
Oil (per Bbl)	$ 115.00	$ 115.00	$ 115.00	$ 115.00	$ 115.00	$ 115.00
Natural gas (per MMBtu)	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00
Assumed realized sales price[3]:						
Oil (per Bbl)	$ 107.47	$ 107.46	$ 107.47	$ 107.46	$ 107.45	$ 107.44
Natural gas (per Mcf)	$ 2.51	$ 2.51	$ 2.50	$ 2.50	$ 2.51	$ 2.50
Developed Properties net profits, net to the trust:						
Gross profits[4]:						
Oil sales	$ 9,229	$ 9,458	$ 9,090	$ 9,326	$ 9,273	$ 8,982
Natural gas sales	54	55	54	55	55	53
Total sales	$ 9,283	$ 9,513	$ 9,144	$ 9,381	$ 9,328	$ 9,035
Developed Properties costs, net to the trust[5]:						
Direct operating expenses[6]:						
Lease operating expenses	$ 2,417	$ 2,415	$ 2,614	$ 2,426	$ 2,442	$ 2,671
Production and other taxes	301	309	297	305	303	293
Development expenses, net[7]		152	631	1,580	352	366
Settlement of commodity derivative contracts, net to the trust[8]						
Total	$ 2,718	$ 2,876	$ 3,542	$ 4,311	$ 3,097	$ 3,330
Developed Properties Net Profits Interest	$ 6,565	$ 6,637	$ 5,602	$ 5,070	$ 6,231	$ 5,705
Remaining Properties Royalty Interest[9]						
PCEC operating and services fee[10]	(83)	(83)	(83)	(83)	(83)	(83)
Net payments to the trust	$ 6,482	$ 6,554	$ 5,519	$ 4,987	$ 6,148	$ 5,622
Trust general and administrative expenses[11]	(71)	(71)	(71)	(71)	(71)	(71)
Cash available for distribution by the trust	$ 6,411	$ 6,483	$ 5,448	$ 4,916	$ 6,077	$ 5,551
Cash distribution per trust unit (assumes units)	$	$	$	$	$	$

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Projected Cash Distributions to Trust Unitholders	Projections for the Month Ending						12 Months Ending
	12/31/12	1/31/13	2/28/13	3/31/13	4/30/13	5/31/13	5/31/13
Developed Properties sales volumes, net to the trust(1):							
Oil (MBbl)	86.5	83.5	86.5	86.8	79.0	87.7	1,025.2
Natural gas (MMcf)	21.8	21.0	21.6	21.3	19.1	21.0	256.0
Total Sales (MBoe)	90.1	87.0	90.1	90.4	82.2	91.2	1,067.8
Daily production (Boe)	2,906.5	2,901.0	2,906.3	2,914.9	2,936.7	2,940.7	2,925.6
Commodity prices(2):							
Oil (per Bbl)	$ 115.00	$ 115.00	$ 115.00	$ 115.00	$ 115.00	$ 115.00	$ 115.00
Natural gas (per MMBtu)	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00
Assumed realized sales price(3):							
Oil (per Bbl)	$ 107.42	$ 107.40	$ 107.37	$ 107.32	$ 107.25	$ 107.21	$ 107.39
Natural gas (per Mcf)	$ 2.50	$ 2.51	$ 2.51	$ 2.51	$ 2.51	$ 2.51	$ 2.51
Developed Properties net profits, net to the trust:							
Gross profits(4):							
Oil sales	$ 9,287	$ 8,971	$ 9,288	$ 9,316	$ 8,477	$ 9,399	$ 110,096
Natural gas sales	55	53	55	53	48	53	643
Total sales	$ 9,342	$ 9,024	$ 9,342	$ 9,370	$ 8,525	$ 9,452	$ 110,739
Developed Properties costs, net to the trust(5):							
Direct operating expenses(6):							
Lease operating expenses	$ 2,707	$ 2,511	$ 2,519	$ 2,542	$ 2,549	$ 2,552	$ 30,365
Production and other taxes	303	292	303	303	275	305	3,589
Development expenses, net(7)	964	686	716	128			5,575
Settlement of commodity derivative contracts, net to the trust(8)							
Total	$ 3,974	$ 3,489	$ 3,538	$ 2,973	$ 2,824	$ 2,857	$ 39,529
Developed Properties Net Profits Interest	$ 5,368	$ 5,535	$ 5,804	$ 6,397	$ 5,701	$ 6,595	$ 71,210
Remaining Properties Royalty Interest(9)	1	2	6	15	24	43	91
PCEC operating and services fee(10)	(83)	(83)	(83)	(83)	(83)	(83)	(1,000)
Net payments to the trust	$ 5,286	$ 5,454	$ 5,727	$ 6,329	$ 5,642	$ 6,555	$ 70,301
Trust general and administrative expenses(11)	(71)	(71)	(71)	(71)	(71)	(71)	(850)
Cash available for distribution by the trust	$ 5,215	$ 5,383	$ 5,656	$ 6,258	$ 5,571	$ 6,484	$ 69,451
Cash distribution per trust unit (assumes units)	$	$	$	$	$	$	$

(1) Sales volumes net to the trust include 80% of sales volumes from the Developed Properties contained in the reserve report for the Underlying Properties.

(2) For a description of the effect of lower crude oil prices on projected cash distributions, please read Sensitivity of Projected Cash Distributions to Oil Production and Prices.

(3) Sales price net of forecasted gravity, quality, transportation, gathering and processing and marketing costs. For more information about the estimates and hypothetical assumptions made in preparing the table above, please read Significant Assumptions Used to Prepare the Projected Cash Distributions.

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(4) Represents gross profits as described in Computation of Net Profits and Royalties Net Profits Interests.
(5) Costs net to the trust include 80% of costs from the Developed Properties contained in the reserve report for the Underlying Properties.
(6) Total direct operating expenses per Boe are projected to be $31.81.
(7) Total development expenses per Boe are projected to be $5.22.
(8) Reflects net cash impact of settlements of commodity derivative contracts relating to production. Please read The Underlying Properties Commodity Derivative Contracts.
(9) Represents the Royalty Interest as described in Computation of Net Profits and Royalties Royalty Interest.
(10) The PCEC operating and services fee relating to production from the Underlying Properties will be $1,000,000 on an annualized basis fee for the twelve months ending March 31, 2013 and will change on an annual basis commencing on April 1, 2013, based on changes to the CPI.
(11) Total general and administrative expenses of the trust on an annualized basis for the twelve months ending March 31, 2013 are expected to be $850,000 and will include the annual fees to the trustees, accounting fees, engineering fees, legal fees, printing costs and other expenses properly chargeable to the trust.

Significant Assumptions Used to Prepare the Projected Cash Distributions

Timing of actual distributions. In preparing the projected cash distributions above and sensitivity analysis below, the revenues and expenses of the trust were calculated based on the terms of the conveyance creating the trust s Conveyed Interests. These calculations are described under Computation of Net Profits and Royalties. It is the intent of the trust to distribute to trust unitholders proceeds received by the trust in the month after the trust receives such funds. Monthly cash distributions will be made to holders of trust units as of the applicable record date (generally the last business day of each calendar month) on or before the 10th business day after the record date. Due to the amount of time it typically takes PCEC to collect payments from its customers, it has been assumed, for purposes of the projections, that cash distributions for each month will include oil and natural gas production from 45 to 75 days prior to the distribution date. The first distribution is expected to be made on or about June 15, 2012, and will include cash received from sales of oil and natural gas production and direct operating and development expenses relating to the month of April 2012.

Production estimates and sales volumes. Production estimates for the twelve months ending March 31, 2013 are based on the reserve reports for the Underlying Properties attached as Annexes A and B to this prospectus. Net sales from the Underlying Properties for the twelve months ending March 31, 2013 is estimated to be 1,307 MBbls of oil and 320 MMcf of natural gas, of which 1,281 MBbls of oil and 320 MMcf of natural gas are attributable to the Developed Properties and 25 MBbls of oil and 0 MMcf of natural gas are attributable to the Remaining Properties. Net sales were 1,086 MBbls of oil and 259 MMcf of natural gas for the year ended December 31, 2010 and were 1,171 MBbls of oil and 264 MMcf of natural gas for the year ended December 31, 2011. PCEC expects an increase in annual production from the Underlying Properties from 2011 to 2012, as reflected in the reserve reports, due to its capital expenditures in the last six months of 2011 and from capital that PCEC expects to spend during the twelve-month projection period. In addition, PCEC experienced an increase in production of approximately 100 MBoe as a result of the consummation of the East Coyote and Sawtelle Reversion in April 2012. Proved developed production at the beginning of the first twelve-month production period is essentially at its highest level and capital development is primarily focused on the undeveloped properties. The amount of capital that is spent on the developed properties will briefly offset the natural decline found in all oil wells. However, the combined effect of the capital expenditures and the decline of all oil wells will result in a 0.6% decline in production at the developed properties from the twelve months ending December 31, 2012 to the twelve months ending December 31, 2013.

Oil and natural gas prices. We have assumed crude oil and natural gas prices of $115.00 per Bbl and $3.00 per Mcf for the twelve months ending May 31, 2013. Average Brent prices were $111.26 per Bbl and $79.61 per Bbl for the year ended December 31, 2011 and year ended December 31, 2010, respectively. The differentials over actual realized sales prices for the year ended December 31, 2011 and year ended December 31, 2010 were

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$20.85 per Bbl and $9.62 per Bbl, respectively and were primarily caused by a new sales contract taking effect during the year. Average Henry Hub prices were $4.00 per Mcf and $4.37 per Mcf for the year ended December 31, 2011 and year ended December 31, 2010, respectively. The differentials over actual realized sales prices for the year ended December 31, 2011 and year ended December 31, 2010 were $0.45 per Mcf and $0.92 per Mcf, respectively. Actual realized sales prices were $90.41 per Bbl and $3.55 per Mcf for the year ended December 31, 2011 and $69.99 per Bbl and $3.45 per Mcf for the year ended December 31, 2010. Differentials between published oil and natural gas prices and the prices actually received for the oil and natural gas production may vary significantly due to market conditions, transportation, gathering and processing costs, quality of production and other factors.

In the above table, an average of $7.61 per Bbl and $0.49 per Mcf is deducted from the assumed crude oil (Brent) and natural gas (Henry Hub) prices, respectively, to reflect these differentials. Crude oil differentials are based on PCEC s estimate of the average difference between the published crude oil prices in California such as the Buena Vista and Midway Sunset postings and the price to be received by PCEC for crude oil production attributable to the Underlying Properties during the twelve months ending March 31, 2013. Substantially all of PCEC s crude 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. PCEC estimates the Buena Vista and Midway Sunset postings to be 98% and 92% of Brent prices, respectively, during the twelve months ending March 31, 2013. Natural gas differentials are based on PCEC s estimate of the average difference between the NYMEX published price of natural gas (Henry Hub) and the price to be received by PCEC for production of natural gas attributable to the Underlying Properties during the twelve months ending March 31, 2013. Assumed realized oil and natural gas prices appearing in this prospectus have been adjusted for these differentials.

The differentials to published oil and natural gas prices applied in the above projected cash distribution estimate are based upon an analysis by PCEC of the historic price differentials for production from the Underlying Properties with consideration given to gravity, quality and transportation and marketing costs that may affect these differentials. There is no assurance that these assumed differentials will occur.

When oil and natural gas prices decline, PCEC may elect to reduce or completely suspend production. No adjustments have been made to estimated production during the twelve months ending March 31, 2013 to reflect potential reductions or suspensions of production.

Settlement of Commodity Derivative Contracts. PCEC has entered into commodity derivative contracts with an affiliate of Wells Fargo in order to mitigate the effects of falling commodity prices through March 31, 2014. The trust will be entitled to the effect of 2,000 barrels of daily swap volumes of Brent crude oil at $115.00 per barrel during the twenty-four months ending March 31, 2014. The commodity derivative contracts are intended to reduce exposure of the revenues from oil production from the Underlying Properties to fluctuations in oil prices and to achieve more predictable cash flow. The commodity derivative contracts will limit the benefit to the trust of any increase in oil prices through March 31, 2014. The trust will not bear any hedge settlement costs paid by PCEC, or be entitled to any hedge payments received by PCEC, for periods on or prior to April 2012. For more information, see The Underlying Properties Commodity Derivative Contracts.

Direct Operating Expenses. For the twelve months ending March 31, 2013, PCEC estimates lease operating expenses relating to the Developed Properties to be approximately $38.0 million and production and other taxes to be approximately $4.5 million. For the twelve months ending March 31, 2013, PCEC estimates lease operating expenses relating to the Remaining Properties to be approximately $1.2 million and production and other taxes to be approximately $0.1 million. For the year ended December 31, 2010, total lease operating expenses were $33.2 million and property and other taxes were $2.4 million. For the year ended December 31, 2011, total lease operating expenses were $36.2 million and property and other taxes were $3.1 million. Royalty Interest Proceeds

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will not be reduced by lease operating expenses but will be reduced by the Royalty Interest s share of production and property taxes and post-production costs. For a description of direct operating expenses, please read Computation of Net Profits and Royalties Net Profits Interests.

Development Expenses. For the twelve months ending March 31, 2013, PCEC estimates development expenses incurred relating to the Developed Properties to be approximately $7.0 million. For the twelve months ending March 31, 2013, PCEC estimates development expenses incurred relating to the Remaining Properties to be approximately $28.1 million. For the year ended December 31, 2010, total development expenses incurred were $44.0 million. For the year ended December 31, 2011, total development expenses incurred were $29.9 million. Royalty Interest Proceeds will not be reduced by development expenses but will be reduced by the Royalty Interest s share of production and property taxes and post-production costs.

Excess Costs. Based on the estimates of production, direct operating expenses and development expenses attributable to the Developed Properties discussed above, the net profits interests relating to the Developed Properties for the twelve months ending March 31, 2013 is expected to be positive. Based on the estimates of production, direct operating expenses and development expenses attributable to the Remaining Properties discussed above, which includes amounts paid for the Royalty Interest Proceeds, the net profits interest relating to the Remaining Properties for the twelve months ending March 31, 2013 is expected to be negative in an amount equal to approximately $6.7 million ($26.7 million attributable to the Underlying Properties). Accordingly, the trust will be entitled to receive the Royalty Interest Proceeds during the projection period and thereafter until the first day of the month following the NPI Payout.

Royalty Interest. For the twelve months ending March 31, 2013, PCEC estimates gross production for the Remaining Properties located on PCEC s Orcutt properties to be 12.0 MBbl of oil. For the twelve months ending March 31, 2013, PCEC estimates average assumed realized oil sales price of $102.95 for this gross production, which is based on an assumed price of $115.00 for oil, net of forecasted gravity, quality, transportation, gathering and processing and marketing costs. For the twelve months ending March 31, 2013, PCEC assumed production taxes applicable to this gross production to be 2.9%.

PCEC operating and services fee and general and administrative expense. The trust will be responsible for paying to PCEC a monthly fee for operating and informational services to be performed by PCEC on behalf of the trust relating to production from the Underlying Properties. The PCEC operating and services fee will be $1,000,000 for the twelve months ending March 31, 2013. The operating and services fee payable to PCEC is an amount equal to $83,333.33 per month and will change on an annual basis commencing on April 1, 2013, based on changes to the CPI. Accordingly, the PCEC operating and services fee for subsequent years could be greater or less depending on future events that cannot be predicted. The PCEC operating and services fee will be charged to the trust by PCEC before distributions are made to trust unitholders.

The trust will be responsible for paying the annual fees to the trustees, all accounting fees, engineering fees, legal fees, printing costs and other out-of-pocket expenses incurred by or at the direction of the trustee or the Delaware trustee. The trust will also be responsible for paying other expenses incurred as a result of being a publicly traded entity, including costs associated with annual, quarterly and monthly reports to trust unitholders, tax return and Form 1099 preparation and distribution, NYSE listing fees, independent auditor fees and registrar and transfer agent fees. These general and administrative expenses are anticipated to be approximately $850,000 for the twelve months ending March 31, 2013. General and administrative expenses could be greater or less depending on future events that cannot be predicted. Included in the estimates is an annual administrative fee of $200,000 and $2,000 for the trustee and Delaware trustee, respectively. The trust will pay, out of the first cash payment received by the trust, the trustee s and Delaware trustee s legal expenses incurred in forming the trust as well as their acceptance fees in the amount of $10,000 and $1,500, respectively. These costs will be deducted by the trust before distributions are made to trust unitholders. Please read The Trust.

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Sensitivity of Projected Cash Distributions to Oil Production and Prices

The amount of revenues of the trust and cash distributions to the trust unitholders will be directly dependent on the sales price for oil production sold from the Underlying Properties, the volumes of oil produced attributable to the Underlying Properties, payments made or received under the commodity derivative contracts and variations in direct operating expenses and development expenses.

The table and discussion below set forth sensitivity analyses of annual cash distributions per trust unit for the twelve months ending May 31, 2013, on the assumption that a trust unitholder purchased a trust unit in this offering and held such trust unit until the monthly record date for distributions for May 31, 2013, based upon (1) the assumption that a total of trust units are issued and outstanding after the closing of the offering made hereby; (2) realization of the production levels estimated in the reserve reports; (3) the hypothetical crude oil prices based upon assumed Brent prices; (4) the impact of the commodity derivative contracts entered into by PCEC that relate to production from the Underlying Properties; and (5) other assumptions described above under Significant Assumptions Used to Prepare the Projected Cash Distributions. The hypothetical crude oil prices shown have been chosen solely for illustrative purposes.

The table below is not a projection or forecast of the actual or estimated results from an investment in the trust units. The purpose of the table below is to illustrate the sensitivity of cash distributions to changes in oil pricing (giving effect to the commodity derivative contracts that will be in place during the twelve months ending March 31, 2013). There is no assurance that the hypothetical assumptions described below will actually occur or that Brent futures prices will not change by amounts different from those shown in the tables.

It is intended that the trust s commodity derivative contracts will be in effect only through March 31, 2014, and thus there is likely to be greater fluctuation in cash distributions resulting from fluctuations in the realized oil prices in periods subsequent to the expiration of those contracts. Please read Risk Factors for a discussion of various items that could impact production levels and the prices of crude oil. Excluding the effects of the commodity derivative contracts, the trust would be unable to make any monthly cash distributions if oil prices were below $43.00 per Bbl.

Sensitivity of Projected Cash Distribution Per Trust Unit

to Changes in NYMEX Futures Pricing

(Period Estimate of April 1, 2012 to March 31, 2013)

Brent Futures Oil Pricing ($ per Bbl of Oil)						
$100	$105	$110	$115	$120	$125	$130
$	$	$	$	$	$	$

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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 approximately 100% of the average daily production associated with these assets and has an average working interest and net revenue interest of approximately 97% and 94%, 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 93% of the average daily production associated with the properties in the Los Angeles Basin for the month ended December 31, 2011.

As of December 31, 2011, the Underlying Properties had proved reserves of 34.1 MMBoe. A majority of the proved reserves attributable to the Underlying Properties are 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. As of December 31, 2011, approximately 62% of the volumes of the proved reserves associated with the Underlying Properties and 81% of the volumes of the proved reserves associated with the trust were attributed to proved developed reserves. In addition, 100% of the Underlying Properties are held by production or owned in fee. Average net sales (after royalties and other interests) from the Underlying Properties for the twelve months ended December 31, 2011 was approximately 3,328 Boe/d (or 2,662 Boe/d attributable to 80% of proved developed reserves on the Underlying Properties), comprised of approximately 98% oil.

The following table sets forth, as of December 31, 2011, certain estimated proved reserves attributable to the Underlying Properties and the Conveyed Interests, in each case derived from the reserve reports.

	Underlying Properties	Conveyed Interests
	(In thousands)	
Proved Reserves		
Oil (MBbls)	33,320	9,584
Natural Gas (MMcf)	4,851	1,594
Oil Equivalents (MBoe)	34,128	9,850
Proved Developed Equivalents (MBoe)	21,124	7,986

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.

Computation of Proved Reserves Attributable to the Conveyed Interests

Pursuant to the terms of the conveyance, net profits and royalty payments from PCEC to the trust are computed monthly. One may determine the reserves attributable to the Conveyed Interests by utilizing the following computations, which must be made separately for the Developed Properties and the Remaining Properties. The resulting amounts identify the quantity of reserves to be sold for profit by PCEC on behalf of the trust.

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Developed Properties

The trust will receive 80% of the net profits from the sale of oil and natural gas production from the Developed Properties. The corresponding reserves attributable to the Developed Properties are determined by adding the total of the net profits payments for the Developed Properties to the trust s share of the production and ad valorem taxes for the Developed Properties for the period covered by the reserve report for the trust and dividing that sum by the effective price per barrel of oil equivalent for the Developed Properties for the period covered by the reserve report for the trust. The resulting reserves are allocated among oil, natural gas and natural gas liquids reserves in proportion with the equivalent amount of production for the Developed Properties during the period covered by the reserve report for the trust. This calculation converts the trust s interest in 80% of the net profits from production from the Developed Properties into the applicable amount of reserves attributable to the Developed Properties.

Remaining Properties

The trust will receive 25% of the net profits from the sale of oil and natural gas production from the Remaining Properties or, when there are no positive net revenues generated by the Remaining Properties or when there is an aggregate negative profit balance for the Remaining Properties, the trust will be paid from a 7.5% overriding royalty interest in the portion of the Remaining Properties located on PCEC s Orcutt properties. The corresponding reserves attributable to the Remaining Properties are determined by adding the total of such payments for the Remaining Properties to the trust s share of the production and ad valorem taxes for the Remaining Properties for the period covered by the reserve report for the trust and dividing that sum by the effective price per barrel of oil equivalent for the Remaining Properties for that month for the period covered by the reserve report for the trust. The resulting reserves are allocated among oil, natural gas and natural gas liquids reserves in proportion with the equivalent amount of production for the Remaining Properties during the period covered by the reserve report for the trust. This calculation converts the trust s interest in 25% of the net profits from production from the Remaining Properties into the applicable amount of reserves attributable to the Remaining Properties.

Operating Areas

The following table summarizes the estimated proved reserves by operating area attributable to the Underlying Properties as of December 31, 2011 according to the reserve report.

					Underlying Properties Proved Reserves as of December 31, 2011[1]		
Properties	**PCEC Operated**		**Average Net Daily Production for the Month Ended December 31, 201 (Boe/d)**	**% Proved Developed Reserves**	**Total (MBoe)[2]**	**% Oil**	**R/P Ratio as of December 31, 2011[3]**
Santa Maria Basin							
Orcutt, Conventional	2004	Present	2,093	100%	11,737	100%	15.4
Orcutt, Diatomite	2005	Present	673	25%	15,563	100%	63.3
Santa Maria Basin Total			2,766	57%	27,300	100%	27.0
Los Angeles Basin							
West Pico[4]	1993	Present	628	65%	3,808	82%	16.6
Sawtelle[5]	1993	April 2012	37	100%	1,346	92%	99.7
East Coyote[5]	1999	April 2012	27	100%	1,674	100%	169.9
Los Angeles Basin Total			692	80%	6,828	88%	27.0
Total			3,458	62%	34,128	98%	27.0

(1) In accordance with the rules and regulations promulgated by the SEC, the proved reserves presented above were determined using the twelve month unweighted arithmetic average of the first-day-of-the-month price

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for the period from January 1, 2011 through December 31, 2011, without giving effect to any hedge transactions, and were held constant for the life of the properties. This yielded average index prices, before adjustments, of $95.97 per Bbl and $4.12 per MMBtu.

(2) Oil equivalents in the table are the sum of the Bbls of oil and the Boe of the stated Mcfs of natural gas, calculated on the basis that six Mcfs of natural gas are the energy equivalent of one Bbl of oil.

(3) The R/P ratio, or the reserves-to-production ratio, is a measure of the number of years that a specified reserve base could support a fixed amount of production. This ratio is calculated by dividing total estimated proved reserves of the subject properties at the end of a period by annual total production for the prior twelve months. Because production rates naturally decline over time, the R/P ratio is not a useful estimate of how long properties should economically produce.

(4) Consists of the West Pico Unit and includes three Stocker JV wells (a joint venture between PCEC and PXP).

(5) In connection with the East Coyote and Sawtelle Reversion, BBEP became the operator of these properties effective April 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 4,482 gross (3,608 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	Cumulative Production (MMBoe)
Monterey / Point Sal	Waterflood	94%	89%	180
SX Sand	Waterflood	100%	100%	0.9
Diatomite	Cyclic steam flood	100%	100%	0.5
Careaga	Collection	100%	100%	0.2

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. Cumulative production from the Monterey and Point Sal is approximately 180 MMBoe. 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. Cumulative production from the SX formation since 2005 is approximately 0.8 MMBoe. 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 125 Monterey, Point Sal and SX formation producing wells, and 58 waterflood injection wells on PCEC s conventional Orcutt properties. PCEC has operated its Orcutt properties for over seven years. PCEC operates 100% of these assets and has an average working interest of approximately 95%.

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

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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 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 one to four weeks, until the well is ready to be steamed again.

The Diatomite formation in the Orcutt oilfield is a shallow zone that lies approximately 100 to 900 feet below the surface. PCEC began cyclic steam development in 2005 and was producing 49 Diatomite wells using the process described above as of December 31, 2011. 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 30 acres to date, and produced over 420 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 130 Bbls/d of the Careaga oil that is pumped from the containers and sold with the rest of its crude oil production. Cumulative production from the Careaga formation is approximately 200 MBoe.

Los Angeles Basin

Similar to the Santa Maria Basin, the Los Angeles Basin is characterized by its mature oilfields with long production histories that have produced more than nine billion Bbls of oil since its discovery in 1892. The Underlying Properties in the Los Angeles Basin consist of the West Pico, Sawtelle and East Coyote properties. These properties are characterized by their long-lived reserves with well established, predictable production profiles and low decline rates. The portion of the Underlying Properties located in the Los Angeles Basin consists of 2,107 gross (1,049 net) acres after giving effect to the East Coyote and Sawtelle Reversion. Prior to the East Coyote and Sawtelle Reversion the portion of the Underlying Properties located in the Los Angeles Basin consisted of 500 net acres.

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

Field	Operator	Recovery Method	Working Interest	Net Revenue Interest	Cumulative Production (MMBoe)
West Pico(1)	PCEC	Waterflood	95.4%	78.5%	70
Sawtelle(2)	BBEP	Waterflood	37.6%	29.0 - 30.5%	19
East Coyote(2)	BBEP	Waterflood	37.6%	35.2%	106

(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 PXP).

(2) Gives effect to the East Coyote and Sawtelle Reversion. Prior to the East Coyote and Sawtelle Reversion, PCEC had an average interest of approximately 5.0% and an average net revenue interest of approximately 3.8% in the East Coyote and Sawtelle properties.

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. Cumulative production from the West Pico Unit is approximately 70 MMBoe. 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 PXP. In accordance with the contractual arrangements with PXP, PXP operates these three wells that were drilled from its facility to three lease line locations between PXP s and PCEC s production units. These wells are equally owned by PCEC and PXP, 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. Cumulative production from the Sawtelle property is approximately 19 MMBoe. 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.

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. Cumulative production from PCEC s East Coyote property is approximately 106 MMBoe. The producing wells are all artificially lifted with rod pumps and electric submersible pumps. There are currently 46 producing wells, and 14 waterflood injection wells in PCEC s East Coyote property.

2012 Capital Budget

For 2012, PCEC has a capital budget of $55.9 million for the Orcutt oilfield in the Santa Maria Basin, of which $49.5 million will be invested in the Orcutt Diatomite properties and $6.4 million will be invested in the conventional Orcutt properties. Of the $49.5 million to be invested in the Orcutt Diatomite properties, $16.3 million will be spent to develop 38 wells at an estimated average cost per well of $430,000, $32.2 million will be spent on facilities and $1.0 million will be spent on workovers, recompletions and test holes. Of the $6.4 million to be invested in the conventional Orcutt properties, $4.3 million will be spent on facilities and $2.1 million will be spent on workovers.

For 2012, PCEC has a capital budget of $10.3 million for the Los Angeles Basin, of which $8.7 million, $0.4 million and $1.3 million will be invested in the West Pico, East Coyote and Sawtelle properties, respectively. Of the $10.3 million to be invested in the Los Angeles Basin, $9.9 million will be spent on facilities and $0.4 million will be spent on artificial lift.

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With respect to the Underlying Properties operated by PCEC, PCEC expects, but is not obligated, to implement the foregoing capital expenditures. Any additional incremental revenue received by PCEC from additional production resulting from future capital expenditures could have the effect of increasing future distributions to the trust unitholders. No assurance can be given, however, that any development well will produce in commercial quantities or that the characteristics of any development well will match the characteristics of PCEC s existing wells or historical drilling success rate.

Operating Data of PCEC (Unaudited)

The following table provides oil and natural gas sales volumes, average sales prices, average costs per Boe and capital expenditures relating to the Underlying Properties for the three years in the period ended December 31, 2011.

	Year Ended December 31,		
	2011	2010	2009
Operating data:			
Sales volumes:			
Oil (MBbls)	1,171	1,086	1,240
Natural gas (MMcf)	264	259	305
Total sales (MBoe)	1,215	1,129	1,291
Average sales prices:			
Oil (per Bbl)	$ 90.41	$ 69.99	$ 53.22
Natural gas (per Mcf)	3.55	3.45	2.72
Average costs per Boe:			
Lease operating expenses	$ 29.82	$ 29.37	$ 27.02
Production and property taxes	2.56	2.08	2.92
Capital expenditures (in thousands):			
Property development costs	$ 29,901	$ 44,000	$ 15,852

Management s Discussion and Analysis of Financial Condition and Results of Operations

Please read Information about Pacific Coast Energy Company LP Management s Discussion and Analysis of Financial Condition and Results of Operations of PCEC.

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 hedge contracts to reduce the exposure of the revenues from oil and natural gas production from the Underlying Properties to fluctuations in oil and natural gas 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.

PCEC has entered into commodity derivative contracts with an affiliate of Wells Fargo in order to mitigate the effects of falling commodity prices through March 31, 2014. The trust will be entitled to the effect of 2,000 barrels of daily swap volumes of Brent crude oil at $115.00 per barrel during the twenty-four months ending March 31, 2014, which represents approximately 70% of expected oil and natural gas production from April 1, 2012 through March 31, 2014 from the proved developed reserves as of December 31, 2011, proportional to the trust s interest in the Developed Properties.

The trust will not bear any commodity derivative settlement costs paid by PCEC, or be entitled to any commodity derivative payments received by PCEC, for periods prior to April 2012.

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The amounts received by PCEC from the commodity derivative contract counterparty upon settlement of the commodity derivative contracts will reduce the operating expenses related to the Underlying Properties in calculating net profits. In addition, the aggregate amounts paid by PCEC on settlement of the commodity derivative contracts related to the Underlying Properties will reduce the amount of net profits paid to the trust. See Computation of Net Profits and Royalties Net Profits Interests.

Producing Acreage and Well Counts

For the following data, gross refers to the total number of wells or acres in which PCEC owns a working interest and net refers to gross wells or acres multiplied by the percentage working interest owned by PCEC. 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 a well is categorized as an oil well or a natural gas well based upon the ratio of oil to natural gas production, 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, 2011.

	Acres	
	Gross	Net
Santa Maria Basin	4,482	3,608
Los Angeles Basin	2,107	500
Total	6,589	4,108

The following is a summary of the producing wells on the Underlying Properties as of December 31, 2011:

	Oil		Natural Gas	
	Gross Wells(1)	Net Wells	Gross Wells(1)	Net Wells
Santa Maria Basin	179	173	0	0
Los Angeles Basin	97	42	0	0
Total	276	215	0	0

(1) PCEC s total wells include 273 operated wells and 3 non-operated wells.

The following is a summary of the number of development and exploratory wells drilled on the Underlying Properties during the last three years.

	Year Ended December 31,					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive	8	8	33	33	11	11
Dry holes	1	1	0	0	1	1
Exploratory Wells:						
Productive	0	0	0	0	0	0
Dry holes	1	1	5	5	0	0
Total:						
Productive	8	8	33	33	11	11
Dry holes	2	2	5	5	1	1

Total	10	10	38	38	12	12

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Reserve Reports

Technologies. The reserve reports were prepared using production performance decline curve analyses to determine the reserves of the Underlying Properties in California. After estimating the reserves of each proved developed property, it was determined that a reasonable level of certainty exists with respect to the reserves which can be expected from any individual undeveloped well in the field. The consistency of reserves attributable to the proved developed wells in California, which cover a wide area, further supports proved undeveloped classification.

Internal controls. Netherland Sewell, the independent petroleum engineering consultant, estimated all of the proved reserve information for the Underlying Properties in this registration statement in accordance with appropriate engineering, geologic and evaluation principles and techniques that are in accordance with practices generally accepted in the petroleum industry, and definitions and guidelines established by the SEC. These reserves estimation methods and techniques are widely taught in university petroleum curricula and throughout the industry s ongoing training programs. Although these engineering, geologic and evaluation principles and techniques are based upon established scientific concepts, the application of such principles and techniques involves extensive judgment and is subject to changes in existing knowledge and technology, economic conditions and applicable statutory and regulatory provisions. These same industry-wide applied techniques are used in determining estimated reserve quantities. The technical person primarily responsible for overseeing preparation of the reserves estimates and the third party reserve reports is Mark L. Pease, the Executive Vice President and Chief Operating Officer of BreitBurn Management, the company that provides services to PCEC GP, the general partner of PCEC. Mr. Pease received a Bachelor of Science in Petroleum Engineering from the Colorado School of Mines in 1979. Prior to joining PCEC, Mr. Pease was Senior Vice President, E&P Technology & Services for Anadarko Petroleum Corporation. Mr. Pease has over 30 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 Netherland Sewell during the reserve estimation process to review properties, assumptions and relevant data. Additionally, PCEC s senior management has reviewed and approved all Netherland Sewell summary reserve reports contained in this prospectus.

The reserves estimates shown herein have been independently evaluated by Netherland Sewell, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. Netherland Sewell was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within Netherland Sewell, the technical persons primarily responsible for preparing the estimates set forth in the Netherland Sewell reserves report incorporated herein are Mr. J. Carter Henson, Jr. and Mr. Mike K. Norton. Mr. Henson has been practicing consulting petroleum engineering at Netherland Sewell since 1989. Mr. Henson is a Licensed Professional Engineer in the State of Texas (No. 73964) and has over 30 years of practical experience in petroleum engineering, with over 22 years 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. Norton has been practicing consulting petroleum geology at Netherland Sewell since 1989. Mr. Norton is a Licensed Professional Geoscientist in the State of Texas, Geology (No. 441) and has over 33 years of practical experience in petroleum geosciences, with over 25 years 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.

Netherland Sewell estimated oil and natural gas reserves attributable to PCEC and the Conveyed Interests as of December 31, 2011 and PCEC as of December 31, 2010. 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.

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The discounted estimated future net revenues presented below were prepared using the twelve month unweighted arithmetic average of the first-day-of-the-month price for the period from January 1, 2011 through December 1, 2011, without giving effect to any hedge transactions, and were held constant for the life of the properties. This yielded average index prices, before adjustments, of $95.97 per Bbl and $4.12 per MMBtu. Oil equivalents in the table are the sum of the Bbls of oil and the Boe of the stated Mcfs of natural gas, calculated on the basis that six Mcfs of natural gas is the energy equivalent of one Bbl of oil. The estimated future net revenues attributable to the Conveyed Interests as of December 31, 2011 are net of the trust s proportionate share of all estimated costs deducted from revenue pursuant to the terms of the conveyance creating the Conveyed Interests. Because oil and natural gas prices are influenced by many factors, use of the twelve month unweighted arithmetic average of the first-day-of-the-month price for the period from January 1, 2011 through December 1, 2011, as required by the SEC, may not be the most accurate basis for estimating future revenues of reserve data. Future net cash flows are discounted at an annual rate of 10%. There is no provision for federal income taxes with respect to the future net cash flows attributable to the Underlying Properties or the Conveyed Interests because future net revenues are not subject to taxation at the PCEC or trust level.

Proved reserves of Underlying Properties. The following table sets forth, as of December 31, 2011, certain estimated proved reserves, estimated future net revenues and the discounted present value thereof attributable to the Underlying Properties and the Conveyed Interests and have been derived from the reserve reports.

	Underlying Properties	Conveyed Interests
	(In thousands)	
Proved Reserves		
Oil (MBbls)	33,320	9,584
Natural Gas (MMcf)	4,851	1,594
Oil Equivalents (MBoe)	34,128	9,850
Future Net Revenues	$ 3,198,157	$ 906,953
Future Production Cost	$ (1,430,646)	$ 25,611
Future Development Cost	$ (251,692)	$
Future Net Cash Flows	$ 1,515,819	$ 881,342
Standardized Measure of Discounted Future Net Cash Flows	$ 661,526	$ 427,272

As proved reserves are evaluated using only direct costs such as production costs, production taxes, work-over, gathering and processing, transportation and drilling costs, if applicable, and other costs such as general and administrative, depreciation, depletion and amortization, interest and derivative losses are not included, the attribution of proved reserves is not necessarily a sign of future overall corporate profitability.

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Changes in Estimated Proved Reserves

The following table summarizes the changes in estimated proved reserves of the Underlying Properties for the periods indicated. The data is presented assuming PCEC owned all the Underlying Properties as of December 31, 2008. In 2011, 2010 and 2009, the unweighted average first-day-of-the-month market prices used to determine oil reserves were $95.97 per Bbl of oil, $79.40 per Bbl of oil and $61.18 per Bbl of oil, respectively, and the market prices used to determine natural gas reserves were $4.12 per MMBtu of gas, $4.38 per MMBtu of gas and $3.87 per MMBtu of gas, respectively. The increase in crude oil prices year over year was the primary reason driving the increase in proved reserves.

	Oil (MBbls)	Natural Gas (MMcf)	Oil Equivalents (MBoe)
Proved Reserves:			
Balance, January 1, 2009	6,851	187	6,882
Revisions of prior estimates	6,723	3,167	7,251
Production	(1,240)	(305)	(1,291)
Balance, December 31, 2009	12,334	3,049	12,842
Revisions of prior estimates	7,260	2,018	7,596
Production	(1,086)	(259)	(1,129)
Balance, December 31, 2010	18,508	4,808	19,309
Revisions of prior estimates	4,357	307	4,408
Extensions, discoveries and other	11,626		11,626
Production	(1,171)	(264)	(1,215)
Balance, December 31, 2011	33,320	4,851	34,128
Proved Developed Reserves:			
Balance, December 31, 2009	11,320	1,475	11,566
Balance, December 31, 2010	16,982	2,879	17,462
Balance, December 31, 2011	20,548	3,458	21,124
Proved Undeveloped Reserves:			
Balance, December 31, 2009	1,014	1,574	1,276
Balance, December 31, 2010	1,526	1,929	1,847
Balance, December 31, 2011	12,772	1,393	13,004

Changes in Proved Undeveloped Reserves

The 11,157 MBoe increase in proved undeveloped reserves during the year ended December 31, 2011, was driven by technical and economic success from positive results from test wells drilled in connection with an expansion at PCEC s Orcutt Diatomite properties. The 571 MBoe increase in proved undeveloped reserves during the year ended December 31, 2010, consists of 409 MBoe positive revisions as a result of higher oil and natural gas prices from production from PCEC s West Pico property and 162 MBoe due to positive results from wells drilled to the SX formation at PCEC s conventional Orcutt properties.

Conversion of Proved Undeveloped Reserves

During 2009, there were five wells drilled on the Underlying Properties, all of which were drilled in the Santa Maria Basin. These five wells were drilled at a cost of $3.4 million and resulted in the conversion of 230 MBoe of reserves from proved undeveloped to proved developed.

During 2010, there were three wells drilled on the Underlying Properties, all of which were drilled in the Los Angeles Basin. These three wells were drilled at a cost of $11.8 million and resulted in the conversion of 263 MBoe of reserves from proved undeveloped to proved developed.

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During 2011, there were two wells drilled on the Underlying Properties, both of which were drilled in the Santa Maria Basin. These two wells were drilled at a cost of $2.2 million and resulted in the conversion of 20 MBoe of reserves from proved undeveloped to proved developed.

Development of Proved Undeveloped Reserves

All proved undeveloped locations are scheduled to be spud within the next five years. PCEC does not recognize proved undeveloped reserves beyond five years.

Reserve Estimates

PCEC has not filed reserve estimates covering the Underlying Properties with any other federal authority or agency.

Sale and Abandonment of Underlying Properties

PCEC or any transferee will have 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 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.

Marketing and Post-Production Services

Pursuant to the terms of the conveyance creating the Conveyed Interests, PCEC will have the responsibility to market, or cause to be marketed, the oil and natural gas production attributable to the Conveyed Interests in the Underlying Properties. The terms of the conveyance creating the Conveyed Interests restrict PCEC from charging any fee for marketing production attributable to the Net Profits Interests 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 Net Profits Interests share of net profits; 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 will be 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 will receive the same processing upgrade or downgrade as PCEC.

During the year ended December 31, 2011, PCEC sold the oil produced from the Underlying Properties to third-party crude 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

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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 crude 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 2011, ConocoPhillips accounted for 97% of PCEC s net sales, and currently ConocoPhillips accounts for all of PCEC s net sales. ConocoPhillips purchase of production from the Orcutt properties is pursuant to a long-term sales contract between ConocoPhillips and PCEC, and its purchase of production from the Sawtelle and West Pico properties is pursuant to a month-to-month sales contract. PCEC does not believe that the loss of ConocoPhillips as a purchaser of crude oil production from the Underlying Properties would have a material impact on the business or operations of PCEC or the Underlying Properties because of the competitive marketing conditions in California.

All natural gas produced by PCEC that is not consumed in its Diatomite production 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.

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.

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PCEC believes that the burdens and obligations affecting the properties comprising the Underlying Properties are conventional in the industry for similar properties. PCEC also 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 will record 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 will be, 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.

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 will be 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.

Environmental Matters and Regulation

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

- obtain permits to conduct regulated activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas;
- restrict the types, quantities and concentration of materials that can be released into the environment in the performance of drilling 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;

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apply specific health and safety criteria addressing worker protection; and

impose substantial liabilities on PCEC for pollution resulting from PCEC s operations.

For all of PCEC s operations, numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, often times requiring difficult and costly actions. 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 increases the cost of doing business in the industry and consequently affects profitability. PCEC believes that it is in substantial compliance with all existing environmental laws and regulations applicable to its current operations and that its continued compliance with existing requirements are reflected in the cash distribution projections contained in this prospectus. However, the clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly construction, drilling, water management, completion, emission or discharge limits or waste handling, disposal or remediation obligations could have a material adverse effect on PCEC s development expenses, results of operations and financial position. PCEC may be unable to pass on those increases to its customers. Moreover, accidental releases or spills may occur in the course of PCEC s operations, and PCEC cannot assure you that it 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. Similarly, 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 EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third-parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. PCEC generates materials in the course of its operations that may be regulated as hazardous substances.

The Resource Conservation and Recovery Act, or RCRA, and comparable state laws regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of 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, or E&P Wastes, now classified as non-hazardous could be classified as hazardous wastes in the future. In September 2010, the Natural Resources Defense Council filed a petition with the EPA to request reconsideration of the exemption of E&P Wastes from regulation as hazardous waste under RCRA (which could also affect E&P Wastes regulation under other environmental laws, including CERCLA).

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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. In addition, PCEC generates industrial wastes in the ordinary course of its operations that may be regulated as hazardous wastes.

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 on or under the real properties upon which PCEC conducts its operations, or on or under 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 thereon may be subject 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 flooding technique has the effect of stimulating the release of low-specific-gravity hydrocarbons from the cap rock formation, which manifest at the surface in a series of small seeps. PCEC regularly 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, into federal and state waters. 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, or SPCC, plan requirements imposed under the Clean Water Act require appropriate containment berms and similar structures to help prevent the contamination of navigable waters 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, or 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, or 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 federal Clean Air Act and comparable state laws restrict the emission of air pollutants from many sources through air emissions permitting programs and also impose various monitoring and reporting requirements. 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. For example, on July 28, 2011, the EPA proposed rules that would establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA s proposed rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds, or VOCs, and a separate set of emission

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standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The proposed rules also would establish specific new requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. In addition, the rules would establish new leak detection requirements for natural gas processing plants. The EPA received public comments regarding the proposed rules and must take final action on the rules by April 17, 2012. If finalized, these rules 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. Obtaining permits has the potential to delay the development of oil and natural gas projects. Federal and state regulatory agencies may 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. For example, in our Orcutt field, we elected to transport our crude oil production by truck during a third-party pipeline spill and associated outage, even though our local air permit requires that we use a pipeline for crude oil transportation. We self-disclosed this non-compliance issue to the local air district and received an associated notice of violation in March 2011. In July 2011, we settled the notice of violation and paid a civil penalty of $183,500.

Climate change. Recent scientific studies have suggested that emissions of certain gases, commonly referred to as GHGs, and including carbon dioxide and methane, may be contributing to warming of the Earth s atmosphere. In response to the scientific studies, international negotiations to address climate change have occurred. The United Nations Framework Convention on Climate Change, also known as the Kyoto Protocol, became effective on February 16, 2005 as a result of these negotiations, but the United States did not ratify the Kyoto Protocol. At the end of 2009, an international conference to develop a successor to the Kyoto Protocol issued a document known as the Copenhagen Accord. Pursuant to the Copenhagen Accord, the United States submitted a greenhouse gas emission reduction target of 17 percent compared to 2005 levels.

Both houses of Congress have actively considered legislation to reduce emissions of GHGs, and almost one-half 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 allowances would be expected to escalate significantly in cost 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. Since then, the California Air Resources Board has taken and plans to take various actions to implement the program, including the approval on December 11, 2008, of an AB32 Scoping Plan summarizing the main GHG-reduction strategies for California. In August 2011, the CARB approved its revised supplemental California Environmental Quality Act, or CEQA, analysis in support of the cap and trade regulatory program. In October 2011, the CARB adopted the final cap-and-trade regulation, including a delay in the start of the cap-and-trade rule s compliance obligations until 2013. The final cap-and-trade system is designed to be in conjunction with the Western Climate Initiative, which currently includes seven states, and four Canadian provinces. 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. 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 would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. The EPA has adopted two sets of regulations under the Clean Air Act. The first limits emissions of GHGs from motor vehicles beginning with the 2012 model year. The EPA has asserted that these final motor vehicle GHG emission standards trigger Clean Air Act construction and operating permit requirements for stationary sources,

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commencing when the motor vehicle standards took effect on January 2, 2011. On June 3, 2010, the EPA published its final rule to address the permitting of GHG emissions from stationary sources under PSD and Title V permitting programs. This rule tailors these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. It is widely expected that facilities required to obtain PSD permits for their GHG emissions also will be required to reduce those emissions according to best available control technology standards for GHG that have yet to be developed. In December 2010, the EPA promulgated Federal Implementation Plans to establish GHG permitting under the PSD program in several jurisdictions in which applicable State Implementation Plans did not accommodate the regulation of GHGs. In many other jurisdictions, applicable State Implementation Plans may provide for GHG permitting under the PSD program. 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. Reporting of GHG emissions from such facilities will be required on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011. 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 greenhouse gas emitting energy sources, PCEC s products would become more desirable in the market with more stringent limitations on greenhouse gas emissions. To the extent that its products are competing with lower greenhouse gas emitting energy, PCEC s products would become less desirable in the market with more stringent limitations on greenhouse gas 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 greenhouse gases 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, or 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 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

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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, or 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 or the California Department of Fish & Game with respect to one or more such species. 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, or 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.

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COMPUTATION OF NET PROFITS AND ROYALTIES

The provisions of the conveyance governing the computation of net profits and royalties are detailed and extensive. The following information summarizes the material information contained in the conveyance related to the computation of net profits and royalties. This summary may not contain all information that is important to you. For more detailed provisions concerning the Conveyed Interests, you should read the conveyance. A form of the conveyance has been filed as an exhibit to the registration statement. Please read Where You Can Find More Information.

The Conveyed Interests entitle the trust to receive 80% of the net profits from the sale of oil and natural gas production from the Developed Properties and either a 7.5% royalty interest from the sale of oil and natural gas production from the Remaining Properties located in 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. 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 amounts associated with the Remaining Properties in the form of Royalty Interest Proceeds until the NPI Payout occurs in approximately 2020.

Net Profits Interests

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 on or before the end of the following month. For any monthly period during which costs for the Remaining Properties exceed gross proceeds, the trust would be entitled to receive the Royalty Interest Proceeds and the trust would continue 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 2020. For a discussion of the Royalty Interest, please read Royalty Interest. PCEC will not pay to the trust any interest on the net profits held by PCEC prior to payment to the trust, provided that such payments are timely made. The trustee will make distributions to trust unitholders monthly. Please read Description of the Trust Units Distributions and Income Computations.

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

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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).

As mentioned above, the costs deducted in the net profits determination will be reduced by certain offset amounts. The offset amounts are further described in the conveyance, and include, among other things, certain net proceeds attributable to the treatment or processing of hydrocarbons produced from the Underlying Properties, 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 would receive Royalty Interest Proceeds, please read Royalty Interest.

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.

Royalty Interest

For any monthly period during which costs for the Remaining Properties exceed gross proceeds, the trust would be 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), which we refer to as the Royalty Interest. Due to significant capital expenditures 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 2020.

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 will not be 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.

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;

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- 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 prospectus), 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.

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.

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DESCRIPTION OF THE TRUST AGREEMENT

The following information and the information included under Description of the Trust Units summarize the material information contained in the trust agreement and the conveyance. For more detailed provisions concerning the trust and the conveyance, you should read the trust agreement, a copy of which has been filed as an exhibit to the registration statement, and the conveyance, a form of which has been filed as an exhibit to the registration statement. Please read Where You Can Find More Information.

Creation and Organization of the Trust; Amendments

Immediately prior to the closing of this offering, PCEC will convey, or cause to be conveyed, to the trust the Conveyed Interests in consideration of the receipt of trust units. The trust s first monthly distribution will consist of an amount in cash paid by PCEC equal to the amount that would have been payable to the trust had the Conveyed Interests been in effect beginning on April 1, 2012, less any general and administrative expenses and reserves of the trust beginning on April 1, 2012. After the offering made hereby, PCEC will own its net interests in the Underlying Properties subject to and burdened by the Conveyed Interests.

The trust was created under Delaware law to acquire and hold 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 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 properties comprising the Underlying Properties. PCEC does not have any contractual commitments to the trust to provide additional funding or to conduct further drilling on or to maintain their ownership interest in any of the Underlying Properties. After the conveyance of the Conveyed Interests, however, PCEC will retain an interest in the Underlying Properties. For a description of the Underlying Properties and other information relating to them, please read The Underlying Properties.

The trust agreement will provide that the trust s business activities will be 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 will not be permitted to acquire other oil and natural gas properties, net profits interests or royalty interests or otherwise to engage in activities beyond those necessary for the conservation and protection of the Conveyed Interests.

The beneficial interest in the trust is divided into trust units. Each of the trust units represents an equal undivided beneficial interest in the assets of the trust. You will find additional information concerning the trust units in Description of the Trust Units.

Amendment of the trust agreement requires the affirmative vote of the holders of at least 75% of the outstanding trust units. However, no amendment may:

- increase the power of the trustee or the Delaware trustee to engage in business or investment activities; or
- alter the rights of the trust unitholders as among themselves.

In addition, certain sections of the trust agreement cannot be amended without the consent of PCEC. Certain amendments to the trust agreement do not require the vote of the trust unitholders. The trustee may, without approval of the trust unitholders, from time to time supplement or amend the trust agreement 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, provided such supplement or amendment does not materially adversely affect the interests of the trust unitholders. The affairs of the trust will be managed by the trustee. PCEC has no ability to manage or influence the operations of the trust and will not owe any fiduciary duties or liabilities to the trust or the unitholders. Likewise, the trust has no ability to manage or influence the operation of PCEC.

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Assets of the Trust

Upon completion of this offering, the assets of the trust will consist of the Conveyed Interests and any cash and temporary investments being held for the payment of expenses and liabilities and for distribution to the trust unitholders.

Duties and Powers of the Trustee

The duties of the trustee are specified in the trust agreement and by the laws of the state of Delaware, except as modified by the trust agreement. The trustee s principal duties consist of:

- collecting cash attributable to the Conveyed Interests;
- paying expenses, charges and obligations of the trust from the trust s assets;
- distributing distributable cash to the trust unitholders;
- causing to be prepared and distributed a tax information report for each trust unitholder and to prepare and file tax returns on behalf of the trust;
- causing to be prepared and filed reports required to be filed under the Exchange Act and by the rules of any securities exchange or quotation system on which the trust units are listed or admitted to trading;
- causing to be prepared and filed a reserve report by or for the trust by independent reserve engineers as of December 31 of each year in accordance with criteria established by the SEC;
- establishing, evaluating and maintaining a system of internal control over financial reporting in compliance with the requirements of Section 404 of the Sarbanes-Oxley Act of 2002;
- enforcing the rights under certain agreements entered into in connection with this offering;
- taking any action it deems necessary, desirable or advisable to best achieve the purposes of the trust; and
- providing to PCEC any unitholder information necessary for PCEC to fulfill any applicable tax withholding requirements.

In connection with the formation of the trust, the trust will enter 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. For example, the trust will enter into an operating and services agreement with PCEC pursuant to which PCEC will perform 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. Additionally, the trustee may from time to time supplement or amend the conveyance, the operating and services agreement and the registration rights agreement to which the trust is a party without the approval of trust unitholders in order to cure any ambiguity, to correct or supplement any defective or inconsistent provisions, to grant any benefit to all of the trust unitholders, to comply with changes in applicable law or to change the name of the trust. Such supplement or amendment, however, may not materially adversely affect the interests of the trust unitholders.

The trustee may create a cash reserve to pay for future liabilities of the trust. 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 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. The trustee may cause the trust to borrow the funds from any person, including itself or its affiliates, but neither the trustee nor any of its affiliates has any intention

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or obligation to do so. The trustee may also cause the trust to mortgage its assets to secure payment of the indebtedness. The terms of such indebtedness and security interest, if funds were loaned by the entity serving as trustee or Delaware trustee or an affiliate thereof, would be similar to the terms which such entity would grant to a similarly situated commercial customer with whom it did not have a fiduciary relationship, and such entity shall be entitled to enforce its rights with respect to any such indebtedness and security interest as if it were not then serving as trustee or Delaware trustee. If the trustee causes the trust to borrow funds, the trust unitholders will not receive distributions until the borrowed funds are repaid.

Each month, the trustee will pay 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 must be invested in:

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

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

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

The trust may merge or consolidate with or convert into one or more limited partnerships, general partnerships, corporations, business trusts, limited liability companies, associations or unincorporated businesses if such transaction is agreed to by the trustee and by the affirmative vote of 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 and such transaction is permitted under the Delaware Statutory Trust Act and any other applicable law.

PCEC may cause the trustee to sell all or any part of the trust estate, including all or any portion of the Conveyed Interests, if approved by the holders of at least 75% of the outstanding trust units. 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 and are conditioned upon an amount equal to the fair value to the trust of such Conveyed Interests being treated as an offset amount against costs and expenses.

Upon dissolution of the trust, the trustee must sell the Conveyed Interests. No trust unitholder approval is required in this event.

The trustee may require any trust unitholder to dispose of his trust units if an administrative or judicial proceeding seeks to cancel or forfeit any of the property in which the trust holds an interest because of the nationality or any other status of that trust unitholder. If a trust unitholder fails to dispose of his trust units, the trustee has the right to purchase them on behalf of the trust and to borrow funds to make that purchase.

The trustee will maintain a website for filings made by the trust with the SEC.

The trustee may agree to modifications of the terms of the conveyance or to settle disputes involving the conveyance without the consent of any trust unitholder. The trustee may not agree to modifications or settle disputes involving the Conveyed Interests part of the conveyance if these actions would change the character of

the Conveyed Interests in such a way that the Conveyed Interests becomes a working interest or that the trust would fail to continue to qualify as a grantor trust for U.S. federal income tax purposes.

Fees and Expenses

Because the trust does not conduct an active business and the trustee has little power to incur obligations, it is expected that the trust will only incur liabilities for routine administrative expenses, such as the trustee s fees, accounting, engineering, legal, tax advisory, the PCEC operating and services fee and other professional fees and other fees and expenses applicable to public companies. The trust will also be responsible for paying other expenses incurred as a result of being a publicly traded entity, including costs associated with annual, quarterly and monthly reports to trust unitholders, tax return and Form 1099 preparation and distribution, NYSE listing fees, independent auditor fees and registrar and transfer agent fees. The trust s general and administrative expenses are estimated to be approximately $850,000 for the twelve months ending March 31, 2013. Included in the $850,000 annual estimate is an annual administrative fee of $200,000 and $2,000 for the trustee and Delaware trustee, respectively. The trust will pay, out of the first cash payment received by the trust, the trustee s and Delaware trustee s legal expenses incurred in forming the trust as well as their acceptance fees in the amount of $10,000 and $1,500, respectively. These costs will be deducted by the trust before distributions are made to trust unitholders.

In addition, the PCEC operating and services fee is an amount equal to $83,333.33 per month and will be $1,000,000 for the twelve months ending March 31, 2013. The PCEC operating and services fee will change on an annual basis commencing on April 1, 2013, based on changes to the CPI. Please read The Trust. The PCEC operating and services fee, along with the trust s general and administrative expenses, for subsequent years could be greater or less depending on future events that cannot be predicted. Unit-based compensation expenses associated with the PCEH long term incentive plan, including additional compensation expense resulting from accelerated vesting of non-voting Class A PCEH units upon the initial public offering of trust units, will not have an impact on calculating distributions available to be made to trust unitholders.

PCEC has agreed to provide the trust at the closing of this offering 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.

Fiduciary Responsibility and Liability of the Trustee

The trustee will not make business or investment decisions affecting the assets of the trust except to the extent it enforces its rights under the conveyance related to the Conveyed Interests and the operating and services agreement described above under Duties and Powers of the Trustee that will be executed in connection with this offering. Therefore, substantially all of the trustee s functions under the trust agreement are expected to be ministerial in nature. Please read Duties and Powers of the Trustee above. The trust agreement, however, provides that the trustee may:

- charge for its services as trustee;

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

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- lend funds at commercial rates to the trust to pay the trust s expenses; and
- seek reimbursement from the trust for its out-of-pocket expenses.

In discharging its duty to trust unitholders, the trustee may act in its discretion and will be liable to the trust unitholders only for its own fraud, gross negligence or willful misconduct. The trustee will not be liable for any act or omission of its agents or employees unless the trustee acted with fraud, gross negligence or willful misconduct in their selection, retention or supervision. The trustee will be indemnified individually or as the trustee for any liability or cost that it incurs in the administration of the trust, except in cases of fraud, gross negligence or willful misconduct. The trustee will have a lien on the assets of the trust as security for this indemnification and its compensation earned as trustee. Trust unitholders will not be liable to the trustee for any indemnification. Please read Description of the Trust Units Liability of Trust Unitholders.

The trustee may consult with counsel, accountants, tax advisors, geologists, engineers and other parties the trustee believes to be qualified as experts on the matters for which advice is sought. The trustee will be protected in relying or reasonably acting upon the opinion of the expert.

Except as expressly set forth in the trust agreement, none of PCEC, the trustee, the Delaware trustee nor the other indemnified parties have any duties or liabilities, including fiduciary duties, to the trust or any trust unitholder. The provisions of the trust agreement, to the extent they restrict, eliminate or otherwise modify the duties and liabilities, including fiduciary duties of these persons otherwise existing at law or in equity, are agreed by the trust unitholders to replace such other duties and liabilities of these persons. The trust agreement limits the ability of trust unitholders to enforce provisions of the conveyance creating the Conveyed Interests and PCEC s liability to the trust is limited. However, the limited liability provisions in the trust agreement do not limit the rights of initial purchasers to bring private claims under the federal securities laws; rather, such provisions instead limit the ability of trust unitholders, to the extent permitted by law, to bring claims in the name of the trust or the trust estate, other than claims to compel performance by the trustee on behalf of the trust.

Duration of the Trust; Sale of the Conveyed Interests

The trust will dissolve upon the earliest to occur of the following:

- the trust, upon the approval of the holders of at least 75% of the outstanding trust units, sells the Conveyed Interests;
- the annual cash available for distribution to the trust is less than $2.0 million for each of any two consecutive years;
- the holders of at least 75% of the outstanding trust units vote in favor of dissolution; or
- the trust is judicially dissolved.

The trustee would then 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.

Dispute Resolution

Any dispute, controversy or claim that may arise between PCEC and the trustee relating to the trust will be submitted to binding arbitration before a tribunal of three arbitrators.

Compensation of the Trustee and the Delaware Trustee

The trustee s and the Delaware trustee s compensation will be paid out of the trust s assets. Please read Fees and Expenses.

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California Tax Withholding Waiver

PCEC has received 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 for withholding, and will 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 may not however, be able to obtain such a waiver in the future and, in such a case, PCEC may be required to withhold such amounts.

Miscellaneous

The principal offices of the trustee are located at 919 Congress Avenue, Suite 500, Austin, Texas 78701, and its telephone number is 1-800-852-1422.

The Delaware trustee and the trustee may resign at any time or be removed with or without cause at any time by the affirmative vote of not less than a majority of the trust units present in person or by proxy at a meeting of such holders where a quorum is present. With certain exceptions, any successor must be a bank or trust company meeting certain requirements including having combined capital, surplus and undivided profits of at least $20,000,000, in the case of the Delaware trustee, and $100,000,000, in the case of the trustee.

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DESCRIPTION OF THE 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 will be in book-entry form only and will not be represented by certificates. The trust will have trust units outstanding upon completion of this offering.

Distributions and Income Computations

Each month, the trustee will determine 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 will be reduced by any cash the trustee decides to hold as a reserve against future liabilities. The holders of trust units as of the applicable record date (generally the last business day of each calendar month) are entitled to monthly distributions payable on or before the 10th business day after the record date. The first distribution to trust unitholders purchasing trust units in this offering will be made on or about June 15, 2012 to trust unitholders owning trust units on or about May 31, 2012.

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. Minor variances may occur. For example, the trustee could establish a reserve in one month that would not result in a tax deduction until a later month. Please read United States Federal Income Tax Considerations.

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

Each trust unitholder and his representatives may examine, for any proper purpose, during reasonable business hours, the records of the trust and the trustee, subject to such restrictions as are set forth in the trust agreement.

Liability of Trust Unitholders

Under the Delaware Statutory Trust Act and the trust agreement, trust unitholders will be 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.

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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. Please read Description of the Trust Agreement Creation and Organization of the Trust; Amendments.

Comparison of Trust Units and Common Stock

Trust unitholders have more limited voting rights 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 annual or other periodic re-election of the trustee. The trust does not intend to hold annual meetings of trust unitholders.

You should also be aware of the following ways in which an investment in trust units is different from an investment in common stock of a corporation.

	Trust Units	**Common Stock**
Voting	The trust agreement provides voting rights to trust unitholders to remove and replace the trustee and to approve or disapprove amendments to the trust agreement and certain major trust transactions.	Unless otherwise provided in the certificate of incorporation, the corporate statutes provide voting rights to stockholders to elect directors and to approve or disapprove amendments to the certificate of incorporation and certain major corporate transactions.
Income Tax	The trust is not subject to income tax; trust unitholders are subject to income tax on their pro rata share of trust income, gain, loss and deduction.	Corporations are taxed on their income and their stockholders are taxed on dividends.
Distributions	Substantially all of the cash receipts of the trust are required to be distributed to trust unitholders.	Unless otherwise provided in the certificate of incorporation, stockholders are entitled to receive dividends solely at the discretion of the board of directors.

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	Trust Units	Common Stock
Business and Assets	The business of the trust is limited to specific assets with a finite economic life.	Unless otherwise provided in the certificate of incorporation, a corporation conducts an active business for an unlimited term and can reinvest its earnings and raise additional capital to expand.
Fiduciary Duties	The trustee shall not be liable to the trust unitholders for any of its acts or omissions absent its own fraud, gross negligence or willful misconduct.	Officers and directors have a fiduciary duty of loyalty to the corporation and its stockholders and a duty to exercise due care in the management and administration of a corporation s affairs.

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TRUST UNITS ELIGIBLE FOR FUTURE SALE

General

Prior to this offering, there has been no public market for the trust units. Sales of substantial amounts of the trust units in the open market, or the perception that those sales could occur, could adversely affect prevailing market prices.

Upon completion of this offering, there will be outstanding trust units. All of the trust units sold in this offering, or trust units if the underwriters exercise their option to purchase additional trust units in full, will be freely tradable without restriction under the Securities Act of 1933, as amended, or the Securities Act . All of the trust units outstanding other than the trust units sold in this offering (a total of trust units, or trust units if the underwriters exercise their option to purchase additional trust units in full) will be restricted securities within the meaning of Rule 144 under the Securities Act and may not be sold other than through registration under the Securities Act or pursuant to an exemption from registration, subject to the restrictions on transfer contained in the lock-up agreements described below and in Underwriting.

Lock-Up Agreements

In connection with this offering, PCEC has agreed, for a period of 180 days after the date of this prospectus, not to offer, sell, contract to sell or otherwise dispose of or transfer any trust units or any securities convertible into or exchangeable for trust units unless Barclays Capital Inc. consents to a shorter period, subject to specified exceptions. Please read Underwriting for a description of these lock-up arrangements. Upon the expiration of these lock-up agreements, trust units, or trust units if the underwriters exercise their option to purchase additional trust units in full, will be eligible for sale in the public market under Rule 144 of the Securities Act, subject to volume limitations and other restrictions contained in Rule 144, or through registration under the Securities Act.

Rule 144

The trust units sold in the offering will generally be freely transferable without restriction or further registration under the Securities Act, except that any trust units owned by an affiliate of the trust, including those held by PCEC, may not be resold publicly except in compliance with the registration requirements of the Securities Act or under an exemption under Rule 144 or otherwise. Rule 144 permits securities acquired by an affiliate to be sold into the market in an amount that does not exceed, during any three-month period, the greater of:

- 1.0% of the total number of the securities outstanding, or

- the average weekly reported trading volume of the trust units for the four calendar weeks prior to the sale.

Sales under Rule 144 are also subject to specific manners of sale provisions, holding period requirements, notice requirements and the availability of current public information about the trust. A person who is not deemed to have been an affiliate of PCEC or the trust at any time during the three months preceding a sale, and who has beneficially owned his trust units for at least nine months (provided the trust is in compliance with the current public information requirement) or one year (regardless of whether the trust is in compliance with the current public information requirement), would be entitled to sell trust units under Rule 144 without regard to the rule s public information requirements, volume limitations, manner of sale provisions and notice requirements.

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Registration Rights

The trust intends to enter into a registration rights agreement with PCEC in connection with PCEC s contribution to the trust of the Conveyed Interests. In the registration rights agreement, the trust will agree, for the benefit of PCEC and any transferee of PCEC s trust units, or the holders, to register the trust units they hold. Specifically, the trust will agree:

- subject to the restrictions described above under Lock-Up Agreements and under Underwriting Lock-Up Agreements, to use its reasonable best efforts to file a registration statement, including, if so requested, a shelf registration statement, with the SEC as promptly as practicable following receipt of a notice requesting the filing of a registration statement from holders representing a majority of the then outstanding registrable trust units;

- to use its commercially reasonable efforts to cause the registration statement or shelf registration statement to be declared effective under the Securities Act as promptly as practicable after the filing thereof; and

- to use its commercially reasonable efforts to maintain the effectiveness of the registration statement under the Securities Act for 90 days (or for three years if a shelf registration statement is requested) after the effectiveness thereof or until the trust units covered by the registration statement have been sold pursuant to such registration statement, PCEC ceases to be an affiliate of the trust for 10 years or until all registrable trust units:

  - have been sold pursuant to Rule 144 under the Securities Act if the transferee thereof does not receive restricted securities ;

  - have been sold in a private transaction in which the transferor s rights under the registration rights agreement are not assigned to the transferee of the trust units;

  - are held by the trust; or

  - have been sold in a private transaction in which the transferor s rights under the registration rights agreement are assigned to a transferee that is not an affiliate of the trust and one year has passed since such transfer.

The holders will have the right to require the trust to file no more than five registration statements in aggregate.

In connection with the preparation and filing of any registration statement, 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.

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UNITED STATES FEDERAL INCOME TAX CONSIDERATIONS

This section is a summary of the material U.S. federal income tax considerations that may be relevant to prospective trust unitholders and, unless otherwise noted in the following discussion, is the opinion of Latham & Watkins LLP, counsel to the trust, insofar as it relates to legal conclusions with respect to matters of U.S. federal income tax law. This section is based upon current provisions of the Internal Revenue Code of 1986, as amended, or the Code, existing and proposed Treasury regulations promulgated under the Code, or the Treasury Regulations, and current administrative rulings and court decisions, all of which are subject to change or different interpretation at any time, possibly with retroactive effect. Later changes in these authorities may cause the U.S. federal income tax consequences to vary substantially from the consequences described below.

The following discussion does not comment on all federal income tax matters affecting the trust or trust unitholders. The following discussion is limited to trust unitholders who hold the trust units as capital assets (generally, property held for investment). All references to trust unitholders (including U.S. trust unitholders and non-U.S. trust unitholders) are to beneficial owners of the trust units. This summary does not address the effect of the U.S. federal estate or gift tax laws or the tax considerations arising under the law of any state (except as provided in the limited summary below under State Tax Considerations), local or non-U.S. jurisdiction. Moreover, the discussion has only limited application to trust unitholders 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 (as defined below) 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 (as defined below) 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.

Prospective investors are urged to consult their tax advisors as to the particular tax consequences to them of the ownership and disposition of an investment in trust units, including the applicability of any U.S. federal income, federal estate or gift tax, state, local and foreign tax laws, changes in applicable tax laws and any pending or proposed legislation.

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As used herein, the term U.S. trust unitholder means a beneficial owner of trust units that for U.S. federal income tax purposes is:

- an individual who is a citizen of the United States or who is a resident of the United States for U.S. federal income tax purposes,
- a corporation, or an entity treated as a corporation for U.S. federal income tax purposes, created or organized in or under the laws of the United States, a state thereof or the District of Columbia,
- an estate the income of which is subject to U.S. federal income taxation regardless of its source, or
- a trust if it is subject to the primary supervision of a U.S. court and the control of one or more United States persons (as defined for U.S. federal income tax purposes) or that has a valid election in effect under applicable U.S. Treasury Regulations to be treated as a United States person.

The term non-U.S. trust unitholder means any beneficial owner of a trust unit that is an individual, corporation, estate or trust and that is not a U.S. trust unitholder.

If a partnership (including for this purpose any entity or arrangement treated as a partnership for U.S. federal income tax purposes) is a beneficial owner of trust units, the tax treatment of a partner in the partnership will depend upon the status of the partner and the activities of the partnership. A trust unitholder that is a partnership, and the partners in such partnership, should consult their own tax advisors about the U.S. federal income tax consequences of purchasing, owning and disposing of trust units.

Classification and Taxation of the Trust

In the opinion of Latham & Watkins LLP, for U.S. federal income tax purposes, the trust will be treated as a grantor trust and not as an unincorporated business entity. As a grantor trust, the trust will not be subject to tax at the trust level. Rather, the grantors, who in this case are the trust unitholders, will be considered, for U.S. federal income tax purposes, to own and receive the trust s assets and income and will be directly taxable thereon as though no trust were in existence.

No ruling has been or will be requested from the IRS with respect to the U.S. federal income tax treatment of the trust, including a ruling as to the status of the trust as a grantor trust or as a partnership for U.S. federal income tax purposes. Thus, no assurance can be provided that the opinions and statements set forth in this discussion of U.S. federal income tax considerations would be sustained by a court if contested by the IRS.

Reporting Requirements for Widely-Held Fixed Investment Trusts

Under Treasury Regulations, the trust is classified as a widely-held fixed investment trust. Those Treasury Regulations require the sharing of tax information among trustees and intermediaries that hold a trust interest on behalf of or for the account of a beneficial owner or any representative or agent of a trust interest holder of fixed investment trusts that are classified as widely-held fixed investment trusts. These reporting requirements provide for the dissemination of trust tax information by the trustee to intermediaries who are ultimately responsible for reporting the investor-specific information through Form 1099 to the investors and the IRS. Every trustee or intermediary that is required to file a Form 1099 for a trust unitholder must furnish a written tax information statement that is in support of the amounts as reported on the applicable Form 1099 to the trust unitholder. 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.

Direct Taxation of Trust Unitholders

Because the trust will be treated as a grantor trust for U.S. federal income tax purposes, trust unitholders will be treated for such purposes as owning a direct interest in the assets of the trust, and each trust unitholder

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will be taxed directly on his pro rata share of the income and gain attributable to the assets of the trust and will be entitled to claim his pro rata share of the deductions and expenses attributable to the assets of the trust (subject to certain limitations discussed below). Information returns will be filed as required by the widely held fixed investment trust rules, reporting to the trust unitholders all items of income, gain, loss, deduction and credit, which will be allocated based on record ownership on the monthly record dates and must be included in the tax returns of the trust unitholders. Income, gain, loss, deduction and credits attributable to the assets of the trust will be taken into account by trust unitholders consistent with their method of accounting and without regard to the taxable year or accounting method employed by the trust.

Following the end of each month, the trustee will determine the amount of funds available as of the end of such month for distribution to the trust unitholders and will make distributions of available funds, if any, to the trust unitholders on or before the 10th business day after the record date, which will generally be on or about the last business day of each calendar month. In certain circumstances, however, a trust unitholder will not receive a distribution of cash attributable to the income from a month. For example, if the trustee establishes a reserve or borrows money to satisfy liabilities of the trust, income associated with the cash used to establish that reserve or to repay that loan must be reported by the trust unitholder, even though that cash is not distributed to him.

As described above, the trust will allocate items of income, gain, loss, deductions and credits to trust unitholders based on record ownership on the monthly record dates. It is possible that the IRS could disagree with this allocation method and could assert that income and deductions of the trust should be determined and allocated on a daily or prorated basis, which could require adjustments to the tax returns of the unitholders affected by the issue and result in an increase in the administrative expense of the trust in subsequent periods.

The trust estimates that a purchaser of trust units in this offering who owns such trust units through the record date for distributions for the month ending December 31, 2014, will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be less than 40% of the cash distributed with respect to that period. These estimates and assumptions are subject to, among other things, numerous business, economic, regulatory, legislative, competitive and political uncertainties beyond the trust s control. Further, the estimates are based on current tax law and tax reporting positions that the trust will adopt and with which the IRS could disagree. Accordingly, the trust cannot assure unitholders that these estimates will prove to be correct. The actual percentage of distributions that will correspond to taxable income could be higher or lower than expected, and any differences could be material and could materially affect the value of the trust units.

Tax Classification of the Net Profits Interests and the Royalty Interest

For U.S. federal income tax purposes, the Net Profits Interests attributable to the Developed Properties, or the Developed NPI, and Remaining Properties, or 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, 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

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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. Please read Tax Consequences to U.S. Trust Unitholders.

PCEC and the trust intend to treat the portion of the purchase price of the trust units attributable to the right to receive a distribution based on the income from and after April 1, 2012 attributable to production from the Underlying Properties for the period commencing April 1, 2012, and ending on the closing date of this offering as a tax-free return of capital when such distribution is received. The tax treatment of such a distribution portion is subject to uncertainty because there are no authorities that directly address the treatment of such a payment. For instance, it is possible that no portion of the purchase price of the trust units is attributable to the right to receive such distribution; in such case, no portion of such distribution would be treated as a tax-free return of capital when received, but rather the full amount of such distribution would be subject to tax as ordinary income. As a result of such uncertainty, Latham & Watkins LLP is unable to opine on the tax treatment of such amounts.

Tax Consequences to U.S. Trust Unitholders

Royalty Income and Depletion

Consistent with the discussion above in Tax Classification of the Net Profits Interests and the Royalty Interest, the payments out of production that are received by the trust in respect of the Conveyed Interests constitute ordinary income received in respect of a mineral royalty interest. Trust unitholders should be entitled to deductions for the greater of either cost depletion or (if allowable) percentage depletion with respect to such income. Although the Code requires each trust unitholder to compute his own depletion allowance and maintain records of his share of the adjusted tax basis of the underlying royalty interests for depletion and other purposes, the trust intends to furnish each of the trust unitholders with information relating to this computation for U.S. federal income tax purposes. Each trust unitholder, however, remains responsible for calculating his own depletion allowance and maintaining records of his share of the adjusted tax basis of the underlying property for depletion and other purposes.

Percentage depletion is generally available with respect to trust unitholders who qualify under the independent producer exemption contained in section 613A(c) of the Code. For this purpose, an independent producer is a person not directly or indirectly involved in the retail sale of oil, natural gas or derivative products or the operation of a major refinery. In general, percentage depletion is calculated as an amount equal to 15% (and, in the case of marginal production, potentially a higher percentage) of the trust unitholder s gross income from the depletable property for the taxable year. The percentage depletion deduction with respect to any property is limited to 100% of the taxable income of the trust unitholder from the property for each taxable year, computed without the depletion allowance or certain loss carrybacks. A trust unitholder that qualifies as an independent producer may deduct percentage depletion only to the extent the trust unitholder s average daily production of domestic crude oil, or the natural gas equivalent, does not exceed 1,000 barrels. This depletable amount may be allocated between oil and natural gas production, with 6,000 cubic feet of domestic natural gas production regarded as equivalent to one barrel of crude oil. The 1,000 barrel limitation must be allocated among the independent producer and controlled or related persons and family members in proportion to the respective production by such persons during the period in question.

In addition to the foregoing limitations, the percentage depletion deduction otherwise available is limited to 65% of a trust unitholder s total taxable income from all sources for the year, computed without the depletion allowance and certain loss carrybacks. Any percentage depletion deduction disallowed because of the 65% limitation may be deducted in the following taxable year if the percentage depletion deduction for such year plus the deduction carryover does not exceed 65% of the trust unitholder s total taxable income for that year. The carryover period resulting from the 65% net income limitation is unlimited.

Unlike cost depletion, percentage depletion is not limited to the adjusted tax basis of the property, although, like cost depletion, it reduces the adjusted tax basis, but not below zero.

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In addition to the limitations on percentage depletion discussed above, the Budget Proposal and certain proposed legislation that includes proposals included in the Budget Proposal propose revisions to certain tax preferences applicable to taxpayers engaged in the exploration and production of natural resources, including the repeal of the deduction for percentage depletion with respect to oil and natural gas wells, in which case only cost depletion would be available. It is uncertain whether this or any other legislative proposals will ever be enacted and, if so, when the new legislation would become effective.

Trust unitholders that do not qualify under the independent producer exemption are generally restricted to depletion deductions based on cost depletion. Cost depletion deductions are calculated by (i) dividing the trust unitholder s allocable share of the adjusted tax basis in the relevant mineral property by the number of mineral units (barrels of oil and thousand cubic feet, or Mcf, of natural gas) remaining in the applicable property as of the beginning of the taxable year and (ii) multiplying the result by the number of mineral units sold from such property within the taxable year. The total amount of deductions based on cost depletion cannot exceed the trust unitholder s share of the total adjusted tax basis in the applicable property.

The foregoing discussion of depletion deductions does not purport to be a complete analysis of the complex legislation and Treasury Regulations relating to the availability and calculation of depletion deductions by the trust unitholders. Further, because depletion is required to be computed separately by each trust unitholder and not by the trust, no assurance can be given, and counsel is unable to express any opinion, with respect to the availability or extent of percentage depletion deductions to the trust unitholders for any taxable year. The trust encourages each prospective trust unitholder to consult his tax advisor to determine whether percentage depletion would be available to him.

Tax Rates

Under current law, the highest marginal U.S. federal income tax rate applicable to ordinary income of individuals is 35% and the highest marginal U.S. federal income tax rate applicable to long-term capital gains (generally, capital gains on certain assets held for more than twelve months) of individuals is 15%. However, absent new legislation extending the current rates, beginning January 1, 2013, the highest marginal U.S. federal income tax rate applicable to ordinary income and long-term capital gains of individuals will increase to 39.6% and 20%, respectively. Moreover, these rates are subject to change by new legislation at any time.

The recently enacted Health Care and Education Reconciliation Act of 2010 will impose a 3.8% Medicare tax on certain investment income earned by individuals and certain estates and trusts for taxable years beginning after December 31, 2012. For these purposes, investment income would generally include certain income derived from investments such as the trust units and gain realized by a trust unitholder from a sale of trust units. In the case of an individual, the tax will be imposed on the lesser of (i) the trust unitholder s net income from all investments and (ii) the amount by which the trust unitholder s modified adjusted gross income exceeds $250,000 (if the trust unitholder is married and filing jointly or a surviving spouse), $125,000 (if the trust unitholder is married and filing separately) or $200,000 (in any other case). In the case of an estate or trust, the tax will be imposed on the lesser of (1) undistributed net investment income, or (2) the excess adjusted gross income over the dollar amount at which the highest income tax bracket applicable to an estate or trust begins.

Non-Passive Activity Income and Loss

Under current law, the income and losses of the trust will not be taken into account in computing the passive activity losses and income under Code section 469 for a trust unitholder who acquires and holds trust units as an investment.

Disposition of Trust Units

For U.S. federal income tax purposes, a sale of trust units will be treated as a sale by the U.S. trust unitholder of his interest in the assets of the trust. Generally, a U.S. trust unitholder will recognize gain or loss on a sale or exchange of trust units equal to the difference between the amount realized and the U.S. trust unitholder s adjusted tax basis for the trust units sold. A U.S. trust unitholder s adjusted tax basis in his trust units will be equal to the U.S. trust unitholder s original purchase price for the trust units, reduced by deductions for depletion claimed by the trust unitholder, but not below zero. Except to the extent of the depletion recapture amount explained below, gain or loss on the sale of trust units by a trust unitholder who is an individual will generally be capital gain, and will be long-term capital gain, which is generally subject to tax at preferential rates, if the trust units have been held for more than twelve months. The deductibility of capital losses is limited. Upon the sale or other taxable disposition of his trust units, a trust unitholder will be treated as having sold his share of the Conveyed Interests and must treat as ordinary income his depletion recapture amount, which is an amount equal to the lesser of the gain on such sale or other taxable disposition or the sum of the prior depletion deductions taken with respect to the trust units, but not in excess of the initial tax basis of the trust units. The IRS could take the position that an additional portion of the sales proceeds is ordinary income to the extent of any accrued income at the time of the sale that was allocable to the trust units sold even though the income is not distributed to the selling trust unitholder.

Trust Administrative Expenses

Expenses of the trust will include administrative expenses of the trustee. Certain miscellaneous itemized deductions may be subject to general limitations on deductibility. Under these rules, administrative expenses attributable to the trust units are miscellaneous itemized deductions that generally will have to be aggregated with an individual unitholder s other miscellaneous itemized deductions to determine the excess over 2% of adjusted gross income. In addition, absent new applicable legislation, beginning on January 1, 2013, the amount of otherwise allowable itemized deductions for an individual unitholder whose adjusted gross income exceeds a specified amount for a taxable year will be reduced by the lesser of (i) 3% of the unitholder s adjusted gross income over a specified amount, and (ii) 80% of the amount of itemized deductions that are otherwise allowable for such year. It is anticipated that the amount of such administrative expenses will not be significant in relation to the trust s income.

Information Reporting and Backup Withholding

Distributions of trust income and the proceeds of dispositions of the trust units may be subject to information reporting and backup withholding if the trust unitholder fails to supply an accurate taxpayer identification number or otherwise comply with applicable U.S. information reporting or certification requirements. Any amounts so withheld will be allowed as a credit against the trust unitholder s U.S. federal income tax liability.

Tax Treatment Upon Sale of the Conveyed Interests

The sale of the Conveyed Interests by the trust at or shortly after the date of dissolution of the trust will generally give rise to capital gain or loss to the trust unitholders for U.S. federal income tax purposes, except that any gain will be taxed at ordinary income rates to the extent of depletion deductions that reduced the trust unitholder s adjusted basis in the Conveyed Interests. Such gain or loss will generally be long-term capital gain or loss, which is generally subject to tax at preferential rates, if the trust has been in existence and the trust unitholder has held his trust units for more than twelve months. The IRS could take the position that an additional portion of the sales proceeds is ordinary income to the extent of any accrued income at the time of the sale that was allocable to the trust units even though the income is not distributed to the trust unitholders.

Tax Consequences to Non-U.S. Trust Unitholders

The following is a summary of the material U.S. federal income tax consequences that will apply to you if you are a non-U.S. trust unitholder. Non-U.S. trust unitholders should consult their tax advisors to determine the U.S. federal, state, local and foreign tax consequences that may be relevant to them.

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Payments with Respect to the Trust Units

A non-U.S. trust unitholder will be subject to federal withholding tax on his share of gross royalty income from the Conveyed Interests. The withholding tax will apply at a 30% rate, or lower applicable treaty rate, to the gross royalty income received by the non-U.S. trust unitholder without the benefit of any deductions. However, if such gross royalty income is income effectively connected with a U.S. trade or business conducted by a non-U.S. trust unitholder and the non-U.S. trust unitholder provides an appropriate statement to that effect on IRS Form W-8ECI (or suitable substitute or successor form), then, unless an applicable tax treaty provides otherwise, such non-U.S. trust unitholder generally will be subject to U.S. federal income tax with respect to all such gross royalty income in the same manner as a U.S. trust unitholder, as described above. If such non-U.S. trust unitholder is a corporation, a branch profits tax (currently at the rate of 30%) may apply unless an applicable tax treaty provides otherwise.

Sale or Exchange of Trust Units

The Conveyed Interests will be treated as United States real property interests for U.S. federal income tax purposes. However, as long as the trust units are traded on an established securities exchange, gain realized on the sale or other taxable disposition of a trust unit by a non-U.S. trust unitholder will be subject to federal income tax only if:

- the gain is otherwise effectively connected with business conducted by the non-U.S. trust unitholder in the United States (and, in the case of an applicable tax treaty, is attributable to a permanent establishment or fixed base maintained in the United States by the non-U.S. trust unitholder);
- the non-U.S. trust unitholder is an individual who is present in the United States for at least 183 days in the year of the sale or other taxable disposition and certain other conditions are met; or
- the non-U.S. trust unitholder owns currently, or owned at certain earlier times, directly, or by applying certain attribution rules, more than 5% of the trust units.

Gain realized by a non-U.S. trust unitholder upon the sale or other taxable disposition by the trust of all or any part of the Conveyed Interests would be subject to federal income tax, and distributions to the non-U.S. trust unitholder will be subject to withholding of U.S. tax (currently at the rate of 35%) to the extent distributions are attributable to such gains.

Information Reporting and Backup Withholding

A non-U.S. trust unitholder generally will not be subject to backup withholding and information reporting with respect to payments from the trust, provided that we do not have actual knowledge or reason to know that such non-U.S. trust unitholder is a United States person, within the meaning of the Code, and the non-U.S. trust unitholder has provided the statement described above in Tax Consequences to Non-U.S. Trust Unitholders Payments with Respect to the Trust Units. In addition, a non-U.S. trust unitholder will generally not be subject to backup withholding or information reporting with respect to the proceeds of the sale or other disposition of trust units within the United States or conducted through certain U.S.-related brokers, if the payor receives the statement described above and does not have actual knowledge or reason to know that such non-U.S. trust unitholder is a United States person or the non-U.S. trust unitholder otherwise establishes an exemption. However, payments to non-U.S. trust unitholders of gross royalty income from the Conveyed Interests, and amounts withheld from such payments, if any, generally will be required to be reported to the IRS and to the non-U.S. trust unitholder through Form 1042-S.

Backup withholding is not an additional tax. A non-U.S. trust unitholder generally will be entitled to credit any amounts withheld under the backup withholding rules against the non-U.S. trust unitholder s United States federal income tax liability or may claim a refund provided that the required information is furnished to the IRS in a timely manner.

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Tax Consequences to Tax Exempt Organizations

Employee benefit plans and most other organizations exempt from U.S. federal income tax including IRAs and other retirement plans are subject to U.S. federal income tax on unrelated business taxable income. Because the trust s income is not expected to be unrelated business taxable income, such a tax-exempt organization is not expected to be taxed on income generated by ownership of trust units so long as neither the property held by the trust nor the trust units are treated as debt-financed property within the meaning of Section 514(b) of the Code. In general, trust property would be debt-financed if the trust incurs debt to acquire the property or otherwise incurs or maintains a debt that would not have been incurred or maintained if the property had not been acquired and a trust unit would be debt-financed if the trust unitholder incurs debt to acquire the trust unit or otherwise incurs or maintains a debt that would not have been incurred or maintained if the trust unit had not been acquired.

PROSPECTIVE INVESTORS IN TRUST UNITS ARE STRONGLY ENCOURAGED TO CONSULT THEIR TAX ADVISORS WITH RESPECT TO THE TAX CONSEQUENCES TO THEM OF THE PURCHASE, OWNERSHIP AND DISPOSITION OF THE TRUST UNITS IN LIGHT OF THEIR OWN PARTICULAR CIRCUMSTANCES, INCLUDING THE TAX CONSEQUENCES UNDER STATE, LOCAL, FOREIGN AND OTHER TAX LAWS AND THE POSSIBLE EFFECTS OF CHANGES IN UNITED STATES FEDERAL OR OTHER TAX LAWS.

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STATE TAX CONSIDERATIONS

The following is a brief summary of certain information regarding state income taxes and other state tax matters affecting individuals who are trust unitholders. No opinion of counsel has been requested or received with respect to the state tax consequences of an investment in trust units. The trust is not providing any tax advice with respect to the state tax consequences applicable to any particular purchaser of trust units. Accordingly, prospective investors are urged to consult their tax advisors with respect to these matters.

The trust will own net profits and overriding royalty interests burdening specified oil and natural gas properties located in the state of California. California currently imposes a personal income tax on individuals.

California imposes income taxes upon residents and nonresidents. In the case of nonresidents, income derived from tangible property within the state is subject to tax. The income tax laws of California are based on federal income tax laws. Assuming the trust is taxable as a grantor trust for federal income tax purposes, it will be taxable as a grantor trust for California income tax purposes, and the trust unitholders will be subject to California income tax on their share of income from California net profits and overriding royalty interests. A trust unitholder may be required to file state income tax returns and/or pay taxes in California and may be subject to penalties for failure to comply with such requirements. PCEC has received 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 otherwise not qualifying for an exemption from withholding. PCEC will 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 may not, however, be able to obtain such a waiver in the future and, in such a case, PCEC may be required to withhold such amounts. Any such tax withholding would reduce distributions to these trust unitholders. Trust unitholders subject to California income tax withholding can claim withheld California income tax as a tax prepayment. In addition, under current law, payers that are required to withhold and remit backup withholding to the IRS are also generally required to withhold and remit California backup withholding, currently at a rate of 7%. California backup withholding, if applicable, is in lieu of all other California income tax withholding.

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ERISA CONSIDERATIONS

The Employee Retirement Income Security Act of 1974, as amended, or ERISA, regulates pension, profit-sharing and other employee benefit plans to which it applies. ERISA also contains standards for persons who are fiduciaries of those plans. In addition, the Code provides similar requirements and standards which are applicable to qualified plans, which include these types of plans, and to individual retirement accounts, whether or not subject to ERISA.

A fiduciary of an employee benefit plan should carefully consider fiduciary standards under ERISA regarding the plan s particular circumstances before authorizing an investment in trust units. A fiduciary should consider:

- whether the investment satisfies the prudence requirements of Section 404(a)(1)(B) of ERISA;
- whether the investment satisfies the diversification requirements of Section 404(a)(1)(C) of ERISA; and
- whether the investment is in accordance with the documents and instruments governing the plan as required by Section 404(a)(1)(D) of ERISA.

A fiduciary should also consider whether an investment in trust units might result in direct or indirect nonexempt prohibited transactions under Section 406 of ERISA and Section 4975 of the Code. In deciding whether an investment involves a prohibited transaction, a fiduciary must determine whether there are plan assets in the transaction. The Department of Labor has published final regulations concerning whether or not an employee benefit plan s assets would be deemed to include an interest in the underlying assets of an entity for purposes of the reporting, disclosure and fiduciary responsibility provisions of ERISA and analogous provisions of the Code. These regulations provide that the underlying assets of an entity will not be considered plan assets if the equity interests in the entity are a publicly offered security. PCEC expects that at the time of the sale of the trust units in this offering, they will be publicly offered securities. Fiduciaries, however, will need to determine whether the acquisition of trust units is a nonexempt prohibited transaction under the general requirements of ERISA Section 406 and Section 4975 of the Code.

The prohibited transaction rules are complex, and persons involved in prohibited transactions are subject to penalties. For that reason, potential employee benefit plan investors should consult with their counsel to determine the consequences under ERISA and the Code of their acquisition and ownership of trust units.

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SELLING TRUST UNITHOLDER

Immediately prior to the closing of the offering made hereby, PCEC will convey, or cause to be conveyed, to the trust the Conveyed Interests in exchange for trust units. Of those trust units, are being offered hereby and are subject to the underwriters 30-day option to purchase additional trust units. PCEC has agreed not to sell any of such trust units for a period of 180 days after the date of this prospectus unless Barclays Capital Inc., acting as representative of the several underwriters, consents to a shorter period. Please read Underwriting Lock-Up Agreements. PCEC is deemed to be an underwriter with respect to the trust units offered hereby.

The following table provides information regarding the selling trust unitholder s ownership of the trust units.

	Ownership of Trust Units Before Offering		Number of Trust Units	Ownership of Trust Units After Offering	
Selling Trust Unitholder	Number	Percentage	Being Offered	Number	Percentage
PCEC		100.0%	[(1)]		%

(1) Includes trust units subject to the underwriters 30-day option to purchase additional units.

Prior to this offering, there has been no public market for the trust units. Therefore, if PCEC disposes of all or a portion of the trust units it retains at the closing of this offering, the effect of such disposal on future market prices, if any, of market sales of such remaining trust units or the availability of trust units for sale cannot be predicted. Nevertheless, sales of substantial amounts of trust units in the public market could adversely affect future market prices.

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UNDERWRITING

Barclays Capital Inc., Citigroup Global Markets Inc., Merrill Lynch, Pierce, Fenner and Smith Incorporated, J.P. Morgan Securities LLC, UBS Securities LLC and Wells Fargo Securities, LLC are acting as the representatives of the underwriters of this offering. Under the terms of an underwriting agreement, which will be filed as an exhibit to the registration statement, each of the underwriters named below has severally agreed to purchase from PCEC the respective number of trust units shown opposite its name below:

Underwriters	Number of Trust Units
Barclays Capital Inc.	
Citigroup Global Markets Inc.	
Merrill Lynch, Pierce, Fenner & Smith Incorporated	
J.P. Morgan Securities LLC	
UBS Securities LLC	
Wells Fargo Securities, LLC	
RBC Capital Markets, LLC	
Robert W. Baird & Co. Incorporated	
Stifel, Nicolaus & Company, Incorporated	
Oppenheimer & Co. Inc.	
Janney Montgomery Scott LLC	
Total	

The underwriting agreement provides that the underwriters obligation to purchase trust units depends on the satisfaction of the conditions contained in the underwriting agreement including:

- the obligation to purchase all of the trust units offered hereby (other than those trust units covered by their option to purchase additional trust units as described below), if any of the trust units are purchased;
- the representations and warranties made by the trust and PCEC to the underwriters are true;
- there is no material change in the business of the trust or PCEC or the financial markets; and
- the trust and PCEC deliver customary closing documents to the underwriters.

PCEC is deemed to be an underwriter with respect to the trust units offered hereby.

Commissions and Expenses

The following table summarizes the underwriting discounts and commissions PCEC will pay to the underwriters. These amounts are shown assuming both no exercise and full exercise of the underwriters option to purchase additional trust units. The underwriting fee is the difference between the initial price to the public and the amount the underwriters pay to PCEC for the trust units.

	No Exercise	Full Exercise
Per trust unit		
Total		

Barclays Capital Inc. has advised PCEC that the underwriters propose to offer the trust units directly to the public at the public offering price on the cover of this prospectus and to selected dealers, which may include the underwriters, at such offering price less a selling concession not in excess of $ per trust unit. After the offering, the representative may change the offering price and other selling terms.

The offering of the trust units by the underwriters is subject to receipt and acceptance and subject to the underwriters right to reject any order in whole or in part.

PCEC will pay Barclays Capital Inc. a structuring fee of 0.5% of the gross proceeds of this offering for evaluation, analysis and structuring of the trust.

The expenses of the offering that are payable by PCEC are estimated to be $4,900,000 (excluding underwriting discounts and commissions).

Option to Purchase Additional Trust Units

PCEC has granted the underwriters an option exercisable for 30 days after the date of this prospectus, to purchase, from time to time, in whole or in part, up to an aggregate of trust units at the public offering price less underwriting discounts and commissions. This option may be exercised if the underwriters sell more than trust units in connection with this offering. To the extent that this option is exercised, each underwriter will be obligated, subject to certain conditions, to purchase its pro rata portion of these additional trust units based on the underwriter s underwriting commitment in the offering as indicated in the table at the beginning of this Underwriting Section.

Lock-Up Agreements

PCEC has agreed that, unless Barclays Capital Inc. consents to a shorter period, they will not directly or indirectly, (1) offer for sale, sell, pledge or otherwise dispose of (or enter into any transaction or device that is designed to, or could be expected to, result in the disposition by any person at any time in the future of) any trust units (including, without limitation, trust units that may be deemed to be beneficially owned by them in accordance with the rules and regulations of the SEC and trust units that may be issued upon exercise of any options or warrants) or securities convertible into or exercisable or exchangeable for trust units or sell or grant options, rights or warrants with respect to any trust units or securities convertible into or exchangeable for trust units (other than the sale of the trust units to the underwriters in this offering and other than a pledge of PCEC s trust units under PCEC s senior secured credit facility, provided that PCEC will agree not to acquire any oil or natural gas properties for consideration exceeding $25 million, either individually or in the aggregate, for a period of 90 days after the date of this prospectus), (2) enter into any swap or other derivative transaction that transfers to another, in whole or in part, any of the economic consequences of ownership of the trust units, (3) make any demand for or exercise any right or file or cause to be filed a registration statement, including any amendments thereto, with respect to the registration of any trust units or securities convertible, exercisable or exchangeable into trust units or any other securities of the trust or (4) publicly disclose the intention to do any of the foregoing for a period of 180 days after the date of this prospectus.

The 180-day restricted period described in the preceding paragraph will be extended if:

- during the last 17 days of the 180-day restricted period the trust issues an earnings release or material news or a material event relating to the trust occurs; or

- prior to the expiration of the 180-day restricted period, the trust announces that it will release earnings results during the 16-day period beginning on the last day of the 180-day period,

in which case the restrictions described in the preceding paragraph will continue to apply until the expiration of the 18-day period beginning on the issuance of the earnings release or the announcement of the material news or occurrence of a material event, unless such extension is waived in writing by Barclays Capital Inc.

Barclays Capital Inc., in its sole discretion, may release the trust units and other securities subject to the lock-up agreements described above in whole or in part at any time with or without notice. When determining whether or not to release trust units and other securities from lock-up agreements, Barclays Capital Inc. will consider, among other factors, the holder s reasons for requesting the release, the number of trust units and other securities for which the release is being requested and market conditions at the time. Barclays Capital Inc. has informed PCEC that it does not presently intend to release any trust units or other securities subject to the lock-up agreements.

Offering Price Determination

Prior to this offering, there has been no public market for the trust units. The initial public offering price will be negotiated between the representative and PCEC. In determining the initial public offering price of the trust units, the representative will consider:

- estimates of distributions to trust unitholders;

- overall quality of the oil and natural gas properties attributable to the Underlying Properties;
- the history and prospects for the energy industry;
- PCEC s financial information;
- the prevailing securities markets at the time of this offering; and
- the recent market prices of, and the demand for, publicly traded units of royalty trusts.

Indemnification

The trust and PCEC have agreed to indemnify the several underwriters against certain liabilities, including liabilities under the Securities Act, and to contribute to payments that the underwriters may be required to make for these liabilities.

Selling Restrictions

Public Offer Selling Restrictions Under the Prospectus Directive

In relation to each member state of the European Economic Area that has implemented the Prospectus Directive (each, a relevant member state), with effect from and including the date on which the Prospectus Directive is implemented in that relevant member state (the relevant implementation date), an offer of trust units described in this prospectus may not be made to the public in that relevant member state other than:

- to any legal entity that is a qualified investor as defined in the Prospectus Directive;
- to fewer than 100, or if the relevant member state has implemented the relevant provision of the 2010 PD Amending Directive, 150, natural or legal persons (other than qualified investors as defined in the Prospectus Directive) subject to obtaining the prior consent of the representative for any such offer; or
- in any other circumstances that do not require the publication of a prospectus pursuant to Article 3(2) of the Prospectus Directive,

provided that no such offer of trust units shall require us or any underwriter to publish a prospectus pursuant to Article 3 of the Prospectus Directive.

For purposes of this provision, the expression an offer of trust units to the public in any relevant member state means the communication in any form and by any means of sufficient information on the terms of the offer and the trust units to be offered so as to enable an investor to decide to purchase or subscribe the trust units, as the expression may be varied in that member state by any measure implementing the Prospectus Directive in that member state, and the expression Prospectus Directive means Directive 2003/71/EC (and amendments thereto, including the 2010 PD Amending Directive, to the extent implemented in the relevant member state), and includes any relevant implementing measure in each relevant member state. The expression 2010 PD Amending Directive means Directive 2010/73/EU.

We have not authorized and do not authorize the making of any offer of trust units through any financial intermediary on their behalf, other than offers made by the underwriters with a view to the final placement of the trust units as contemplated in this prospectus. Accordingly, no purchaser of the trust units, other than the underwriters, is authorized to make any further offer of the trust units on behalf of us or the underwriters.

Notice to Prospective Investors in the United Kingdom

The trust may constitute a collective investment scheme as defined by section 235 of the Financial Services and Markets Act 2000 (FSMA) that is not a recognised collective investment scheme for the purposes of FSMA (CIS) and that has not been authorised or otherwise approved. As an unregulated scheme, it

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cannot be marketed in the United Kingdom to the general public, except in accordance with FSMA. This prospectus is only being distributed in the United Kingdom to, and is only directed at:

i) if the trust is a CIS and is marketed by a person who is an authorised person under FSMA, (a) investment professionals falling within Article 14(5) of the Financial Services and Markets Act 2000 (Promotion of Collective Investment Schemes) (Exemptions) Order 2001, as amended (the CIS Promotion Order) or (b) high net worth companies and other persons falling with Article 22(2)(a) to (d) of the CIS Promotion Order; or

ii) otherwise, if marketed by a person who is not an authorised person under FSMA, (a) persons who fall within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005, as amended (the Financial Promotion Order) or (b) Article 49(2)(a) to (d) of the Financial Promotion Order; and

iii) in both cases (i) and (ii) to any other person to whom it may otherwise lawfully be made (all such persons together being referred to as relevant persons).

The trust units are only available to, and any invitation, offer or agreement to subscribe, purchase or otherwise acquire such trust units will be engaged in only with, relevant persons. Any person who is not a relevant person should not act or rely on this document or any of its contents.

An invitation or inducement to engage in investment activity (within the meaning of Section 21 of FSMA) in connection with the issue or sale of any trust units which are the subject of the offering contemplated by this prospectus will only be communicated or caused to be communicated in circumstances in which Section 21(1) of FSMA does not apply to the trust or PCEC.

Stabilization, Short Positions and Penalty Bids

The representative may engage in stabilizing transactions, short sales and purchases to cover positions created by short sales, and penalty bids or purchases for the purpose of pegging, fixing or maintaining the price of the trust units, in accordance with Regulation M under the Exchange Act:

Stabilizing transactions permit bids to purchase the underlying security so long as the stabilizing bids do not exceed a specified maximum.

A short position involves a sale by the underwriters of trust units in excess of the number of trust units the underwriters are obligated to purchase in the offering, which creates the syndicate short position. This short position may be either a covered short position or a naked short position. In a covered short position, the number of trust units involved in the sales made by the underwriters in excess of the number of trust units they are obligated to purchase is not greater than the number of trust units that they may purchase by exercising their option to purchase additional trust units. In a naked short position, the number of trust units involved is greater than the number of trust units in their option to purchase additional trust units. The underwriters may close out any short position by either exercising their option to purchase additional trust units and/or purchasing trust units in the open market. In determining the source of trust units to close out the short position, the underwriters will consider, among other things, the price of trust units available for purchase in the open market as compared to the price at which they may purchase trust units through their option to purchase additional trust units. A naked short position is more likely to be created if the underwriters are concerned that there could be downward pressure on the price of the trust units in the open market after pricing that could adversely affect investors who purchase in the offering.

Syndicate covering transactions involve purchases of the trust units in the open market after the distribution has been completed in order to cover syndicate short positions.

Penalty bids permit the representative to reclaim a selling concession from a syndicate member when the trust units originally sold by the syndicate member are purchased in a stabilizing or syndicate covering transaction to cover syndicate short positions.

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These stabilizing transactions, syndicate covering transactions and penalty bids may have the effect of raising or maintaining the market price of the trust units or preventing or retarding a decline in the market price of the trust units. As a result, the price of the trust units may be higher than the price that might otherwise exist in the open market. These transactions may be effected on the New York Stock Exchange or otherwise and, if commenced, may be discontinued at any time.

None of the trust, PCEC or any of the underwriters make any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of the trust units. In addition, none of the trust, PCEC or any of the underwriters make any representation that the representative will engage in these stabilizing transactions or that any transaction, once commenced, will not be discontinued without notice.

Electronic Distribution

A prospectus in electronic format may be made available on the Internet sites or through other online services maintained by one or more of the underwriters and/or selling group members participating in this offering, or by their affiliates. In those cases, prospective investors may view offering terms online and, depending upon the particular underwriter or selling group member, prospective investors may be allowed to place orders online. The underwriters may agree with PCEC to allocate a specific number of trust units for sale to online brokerage account holders. Any such allocation for online distributions will be made by the representative on the same basis as other allocations.

Other than the prospectus in electronic format, the information on any underwriter s or selling group member s web site and any information contained in any other web site maintained by an underwriter or selling group member is not part of the prospectus or the registration statement of which this prospectus forms a part, has not been approved and/or endorsed by the trust, PCEC or any underwriter or selling group member in its capacity as underwriter or selling group member and should not be relied upon by investors.

New York Stock Exchange

The trust has applied to list the trust units on the New York Stock Exchange under the symbol ROYT. In connection with that listing, the underwriters have undertaken to sell the minimum number of trust units to the minimum number of beneficial owners necessary to meet the New York Stock Exchange listing requirements.

Discretionary Sales

The underwriters have informed PCEC that they do not intend to confirm sales to discretionary accounts that exceed 5% of the total number of trust units offered by them.

Certain Relationships/FINRA Rules

The underwriters and their respective affiliates are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, investment research, principal investment, hedging, financing and brokerage activities. Certain of the underwriters and their respective affiliates have, from time to time, performed, and may in the future perform, various financial advisory and investment banking services for PCEC and the trust, for which they received or will receive customary fees and expenses. Specifically, Citigroup will receive fees in connection with an agreement with PCEC for advisory services provided by Citigroup relating to potential monetization alternatives for PCEC. Additionally, affiliates of Barclays Capital Inc. and Wells Fargo are lenders under PCEC s senior secured credit agreement and an affiliate of Wells Fargo is a lender under PCEC s second lien credit agreement, and each will receive a substantial portion of the proceeds from this offering pursuant to the repayment of a portion of the borrowings thereunder. It is also expected that an affiliate of UBS Securities LLC

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will become a lender under PCEC s senior secured credit facility in connection with the closing of this offering but will not receive any proceeds from this offering. Additionally, an affiliate of Wells Fargo is a party to hedging contracts with PCEC relating to production attributable to the Underlying Properties.

Certain of PCEC s directors are directors and/or employees of Metalmark Capital LLC (Metalmark). All directors and employees of Metalmark are also employees of an affiliate of Citigroup. As described in Pacific Coast Energy Company LP Beneficial Ownership of PCEC, affiliates of Citigroup hold various general and limited partnership interests in certain Metalmark entities, and interests in funds owned and controlled by Metalmark, and so indirectly hold a 51.2% beneficial interest in PCEC and will beneficially own approximately % of the trust units upon the completion of this offering (assuming the underwriters option to purchase additional trust units is not exercised). Additionally, an affiliate of Wells Fargo indirectly holds a 2.56% beneficial interest in PCEC, and so will beneficially own approximately % of the trust units upon the completion of this offering (assuming the underwriters option to purchase additional trust units is not exercised). As a result, affiliates of Citigroup and Wells Fargo will indirectly receive a portion of the proceeds from this offering in connection with the distribution to be made to the equity holders of PCEC, as described in Use of Proceeds.

Because the Financial Industry Regulatory Authority, or FINRA, views the trust units offered hereby as interests in a direct participation program, the offering is being made in compliance with Rule 2310 of the FINRA Conduct Rules. In no event will the maximum amount of compensation to be paid to FINRA members in connection with this offering exceed 10% of the offering proceeds. Investor suitability with respect to the trust units should be judged similarly to the suitability with respect to other securities that are listed for trading on a national securities exchange.

In the ordinary course of their various business activities, the underwriters and their respective affiliates may make or hold a broad array of investments and actively trade debt and equity securities (or related derivative securities) and financial instruments (including bank loans) for their own account and for the accounts of their customers, and such investment and securities activities may involve securities and/or instruments of PCEC and the trust. The underwriters and their respective affiliates may also make investment recommendations and/or publish or express independent research views in respect of such securities or instruments and may at any time hold, or recommend to clients that they acquire, long and/or short positions in such securities and instruments.

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LEGAL MATTERS

Richards, Layton & Finger, P.A., as special Delaware counsel to the trust, will give a legal opinion as to the validity of the trust units. Latham & Watkins LLP, Houston, Texas, will give opinions as to certain other matters relating to the offering, including the tax opinion described in the section of this prospectus captioned United States Federal Income Tax Considerations. Certain legal matters in connection with the trust units offered hereby will be passed upon for the underwriters by Baker Botts L.L.P., Houston, Texas.

EXPERTS

Certain information appearing in this registration statement regarding the December 31, 2010 and December 31, 2011 estimated quantities of reserves of PCEC, the Underlying Properties and the Conveyed Interests owned by the trust, the future net revenues from those reserves and their present value is based on estimates of the reserves and present values prepared by or derived from estimates prepared by Netherland, Sewell & Associates, Inc., independent petroleum engineers.

The PCEC financial statements as of December 31, 2011 and 2010 and for each of the three years in the period ended December 31, 2011 included in this prospectus have been so included in reliance on the reports of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

The Statement of Assets and Trust Corpus of the Pacific Coast Oil Trust as of January 3, 2012 included in this prospectus, has been so included in reliance on the report of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

WHERE YOU CAN FIND MORE INFORMATION

The trust and PCEC have filed with the SEC in Washington, D.C. a registration statement, including all amendments, under the Securities Act relating to the trust units. As permitted by the rules and regulations of the SEC, this prospectus does not contain all of the information contained in the registration statement and the exhibits and schedules to the registration statement. You may read and copy the registration statement at the SEC s public reference room at 100 F Street, N.E., Washington, D.C. 20549. You may request copies of these documents, upon payment of a duplicating fee, by writing to the SEC at the address in the previous sentence. To obtain information on the operation of the public reference room you may call the SEC at (800) SEC-0330. The SEC maintains a web site on the Internet at http://www.sec.gov. The trust s and PCEC s registration statement, of which this prospectus constitutes a part, can be downloaded from the SEC s web site.

The trustee intends to furnish the trust unitholders with annual reports containing the trust s audited consolidated financial statements and to furnish or make available to the trust unitholders quarterly reports containing the trust s unaudited interim financial information for the first three fiscal quarters of each of the trust s fiscal years.

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GLOSSARY OF CERTAIN OIL AND NATURAL GAS TERMS

In this prospectus 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, used herein in reference to crude oil and 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 crude oil equals six Mcf of natural gas.

Boe/d Boe per day.

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

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

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

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

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

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

MBbl One thousand barrels of crude oil or condensate.

MBoe One thousand barrels of oil equivalent.

Mcf One thousand cubic feet of natural gas.

MMBbl One million barrels of crude oil or condensate.

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.

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

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

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 Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods and includes both proved developed producing and proved developed non-producing reserves.

Proved reserves Under SEC rules for fiscal years ending on or after December 31, 2009, proved reserves are defined as:

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

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Under SEC rules for fiscal years ending prior to December 31, 2009, proved reserves are defined as:

The estimated quantities of crude oil and natural gas, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions. Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir. Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based. Estimates of proved reserves do not include the following: (A) Oil that may become available from known reservoirs but is classified separately as indicated additional reserves; (B) crude oil and natural gas, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil and natural gas, that may occur in undrilled prospects; and (D) crude oil and natural gas, that may be recovered from oil shales, coal, gilsonite and other such sources.

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

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.

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.

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INDEX TO FINANCIAL STATEMENTS OF PACIFIC COAST OIL TRUST

PACIFIC COAST OIL TRUST:

The audited financial statements of PCEC can be found beginning on page PCEC F-1.

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Report of Independent Registered Public Accounting Firm

To the Unitholder of Pacific Coast Oil Trust

We have audited the accompanying statement of assets and trust corpus of Pacific Coast Oil Trust as of January 3, 2012. This financial statement is the responsibility of the Trust s management. Our responsibility is to express an opinion on this financial statement based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the statement of assets and trust corpus is free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the statement of assets and trust corpus. 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 audit provides a reasonable basis for our opinion.

As described in Note 2, this financial statement was 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 statement referred to above presents fairly, in all material respects, the assets and trust corpus of Pacific Coast Oil Trust as of January 3, 2012, on the basis of accounting described in Note 2.

/s/ PricewaterhouseCoopers LLP

Los Angeles, California

January 6, 2012

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Pacific Coast Oil Trust

Statement of Assets and Trust Corpus

		January 3, 2012
TRUST CORPUS		
Receivable from PCEC	$	(10)
Trust Corpus	$	10
Total Trust Corpus	$	0

The accompanying notes are an integral part of this financial statement.

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Notes to Statement of Assets and Trust Corpus

Note 1. Organization 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 was created to acquire and hold net profits and royalty interests in PCEC S properties located onshore in California (the Conveyed Interests) for the benefit of the Trust unitholders pursuant to an agreement among PCEC, the Trustee and the Delaware Trustee. In connection with the closing of the initial public offering of trust units, PCEC intends to convey the Conveyed Interests to the Trust in exchange for trust units. 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 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 will 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 7.5% royalty interest from the sale of oil and natural gas production from the other development potential on the Underlying Properties (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.

In connection with the closing of this offering, the trust will enter into an operating and services agreement with PCEC pursuant to which PCEC will provide the Trust with certain operating and informational services relating to the Conveyed Interests in exchange for a monthly fee. The monthly fee will be an amount equal to $83,333.33 per month, which fee will change on an annual basis commencing on April 1, 2013, based on changes to the United States Consumer Price Index (the CPI).

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 unitholder 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.

Note 2. Trust Significant Accounting Policies

(a) 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 net profits interests 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 will be 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:

(i) Income from the Conveyed Interests are recorded when distributions are received by the Trust;

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

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

(iv) PCEC operating and services fee is recorded when paid; and

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

Amortization of the investment in the Conveyed Interests are calculated on a unit-of-production basis and are 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 GAAP, the modified cash basis of reporting revenues, expenses, and distributions is considered to be the most meaningful because monthly distributions to the Trust unitholders are based on net cash receipts. This comprehensive basis of accounting other than GAAP corresponds to the accounting permitted for royalty trusts by the U.S. Securities and Exchange Commission as specified by Staff Accounting Bulletin Topic 12:E, Financial Statements of Royalty Trusts.

To date, the Conveyed Interests have not been conveyed by PCEC to the Trust. Thus, there have been no receipts from the Conveyed Interests and no trust general and administrative expenses nor fees for PCEC operating and services have been incurred.

(b) 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

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 will not be subject to tax at the trust level. Trust unitholders will be treated for such purposes as owning a direct interest in the assets of the Trust, and each trust unitholder will be taxed directly on his pro rata share of the income and gain attributable to the assets of the Trust and will be entitled to claim his pro rata share of the deductions and expenses attributable to the assets of the Trust.

Note 4. 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 the last business day of each calendar month) and are payable on or before the 10th business day after the record date. To date, there have been no distributions.

PACIFIC COAST OIL TRUST

Unaudited Pro Forma Financial Statements

Introduction

The following unaudited pro forma statement of assets and trust corpus and unaudited pro forma statements of distributable income for the Trust have been prepared to illustrate the conveyance of the Conveyed Interests in the Underlying Properties by PCEC to the Trust and the offering of trust units. The unaudited pro forma statement of assets and trust corpus presents the statement of assets and trust corpus of the Trust as of December 31, 2011, as adjusted to give effect to the Conveyed Interests conveyance as if it had occurred on December 31, 2011. The unaudited pro forma statements of distributable income for the year ended December 31, 2011 give effect to the Conveyed Interests conveyance as if it occurred on January 1, 2011, reflecting only pro forma adjustments expected to have a continuing impact on the combined results.

These unaudited pro forma financial statements are for informational purposes only. They do not purport to present the results that would have actually occurred had the Conveyed Interests conveyance been completed on the assumed dates or for the periods presented, or which may be realized in the future.

To produce the pro forma financial statements, management of PCEC made certain estimates. The accompanying unaudited pro forma statement of assets and trust corpus assumes a December 31, 2011 issuance of trust units at an assumed public offering price of $ per unit. The accompanying unaudited pro forma statements of distributable income for the year ended December 31, 2011 have been prepared assuming trust formation and Net Profits Interests conveyance as of January 1, 2011.

These estimates are based on the most recently available information. To the extent there are significant changes in these amounts, the assumptions and estimates herein could change significantly. The unaudited pro forma statement of assets and trust corpus and unaudited pro forma statements of distributable income should be read in conjunction with the accompanying notes to such unaudited pro forma financial statements and the audited statement of assets and trust corpus of the Trust, including the related notes, included in this prospectus and elsewhere in the registration statement.

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Pacific Coast Oil Trust

Unaudited Pro Forma Statement of Assets and Trust Corpus

(in thousands)

	December 31, 2011		
	Historical	**Adjustments**	**Pro Forma**
ASSETS			
Cash	$	$	$
Investment in Conveyed Interests (Note 5)		244,049	244,049
Total assets	$	$ 244,049	$ 244,049
TRUST CORPUS			
Trust Units Issued and Outstanding	$	$ 244,049	$ 244,049

The accompanying notes are an integral part of these unaudited pro forma financial statements

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Pacific Coast Oil Trust

Unaudited Pro Forma Statement of Distributable Income

(in thousands, except per unit amounts)

	Year Ended December 31, 2011
Historical Results	
Income from the Conveyed Interests (Note 4)	$ 30,348
Pro Forma Adjustments	
Less: Trust general and administrative expense (Note 5)	850
Distributable income	$ 29,498
Distributable income per unit	$

The accompanying notes are an integral part of these unaudited pro forma financial statements

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Pacific Coast Oil Trust

Notes to Unaudited Pro Forma Financial Statements

Note 1. Basis of Presentation

In connection with the closing of the initial public offering of trust units, PCEC will convey to Pacific Coast Oil Trust (the Trust), the net profits interests (the Net Profits Interests) and royalty interest (together with the Net Profits Interests, the Conveyed Interests) in the Orcutt properties located onshore in the Santa Maria Basin and the East Coyote, Sawtelle and West Pico properties located onshore in the Los Angeles Basin held by PCEC (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 on the Underlying Properties as of December 31, 2011 (the Developed Properties) and either a 7.5% royalty interest from the sale of oil and natural gas production from the other development potential on the Underlying Properties (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 unaudited pro forma statement of assets and trust corpus presents the statement of assets and trust corpus of the Trust as of December 31, 2011, as adjusted to give effect to the Conveyed Interests conveyance and unit offering as if each had occurred on December 31, 2011. The unaudited pro forma statements of distributable income for the year ended December 31, 2011 give effect to the Conveyed Interests conveyance as if each occurred on January 1, 2011, reflecting only pro forma adjustments expected to have a continuing impact on the combined results.

The Trust was formed in January 2012 under Delaware law to acquire and hold the Conveyed Interests for the benefit of the Trust unitholders. The initial contribution to the Trust was $10.00. The Conveyed Interests are passive in nature, and neither the Trust nor The Bank of New York Mellon Trust Company, N.A., as trustee, will have any control over, or responsibility for, costs relating to the operation of the Underlying Properties.

The unaudited pro forma financial statements should be read in conjunction with the financial statements for PCEC and related notes thereto presented elsewhere in this prospectus.

Note 2. Trust Accounting Policies

These unaudited pro forma financial statements were prepared from the historical revenues for the Underlying Properties. The Trust will use the modified cash basis of accounting to report Trust receipts of the Conveyed Interests and payments of expenses incurred. Actual cash receipts may vary due to timing delays of actual cash receipts from the purchasers or third-party operators. The actual cash distributions of the Trust will be made based on the terms of the conveyance creating the Trust s Conveyed Interests.

PCEC believes that the assumptions used provide a reasonable basis for presenting the significant effects directly attributable to this transaction.

Investment in the Conveyed Interests are recorded initially at historical cost and are periodically assessed to determine whether its aggregate value has been impaired below its total capitalized cost on the Underlying Properties. The Trust will provide a write-down to its investment in the Conveyed Interests to the extent that total capitalized costs, less accumulated depletion, depreciation, and amortization, exceed undiscounted future net revenues attributable to the Trust s interests in the proved oil and natural gas reserves of the Underlying Properties. Any write-down will be based on the amount by which the carrying value exceeds fair value. Fair value is generally determined from estimated discounted future net cash flows.

Note 3. Income Taxes

The Trust is a Delaware statutory trust and is not required to pay federal or state income taxes. Accordingly, no provision for Federal or state income taxes has been made.

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Note 4. Income from Conveyed Interests

The table below outlines the calculation of Trust income from the Conveyed Interests derived from the excess of revenues over direct operating expenses of the Underlying Properties for the year ended December 31, 2011 (in thousands):

	Year Ended December 31, 2011
Revenues of the Underlying Properties	
Oil sales	$ 105,871
Natural gas sales	938
Total revenues	106,809
Direct operating expense of the Underlying Properties	
Direct lease operating expenses(1)	34,613
Production and property taxes	3,110
Total direct operating expenses	37,723
Development costs(2)	(29,901)
Excess of revenues over direct operating expenses and development costs	39,185
Multiplied by Net Profits Interests(3)	80%
Income from Net Profits Interests	31,348
PCEC operating and services fee(4)	(1,000)
Trust income	$ 30,348

(1) Excludes expenses for regional operating management of $1,614 which are not included per the terms of the Net Profits Interests when calculating the distributable income to the Trust.
(2) Per the terms of the Net Profits Interests, development costs are to be deducted when calculating the distributable income to the Trust.
(3) Includes no revenues or expenses attributable to the Remaining Properties.
(4) In connection with the closing of this offering, the Trust will enter into an operating and services agreement with PCEC that obligates the trust to pay to PCEC a monthly services fee for operating and informational services to be performed by PCEC on behalf of the trust relating to the Conveyed Interests. The monthly fee will be an amount equal to $83,333.33, which fee will change on an annual basis commencing on April 1, 2013, based on changes to the CPI.

Note 5. Pro Forma Adjustments

The Conveyed Interests are recorded at the historical cost of PCEC and are calculated as follows as of December 31, 2011 (in thousands):

Historical cost of Underlying Properties	$ 421,207
Less: Asset Retirement Obligations	(22,300)
Less: Accumulated depletion, depreciation and amortization of Underlying Properties	(93,846)
Net property value to be conveyed	305,061
Times 80% Net Profits Interest to Trust	$ 244,049

Estimated annual Trust general and administrative expenses are $850,000 and will include the annual fees to the trustees, accounting fees, engineering fees, legal fees, printing costs and other expenses properly chargeable to the Trust. The Trust s general and administrative expenses for subsequent years could be greater or less depending on future events that cannot be predicted. In connection with the closing of this offering, the trust will enter into an operating and services agreement with PCEC pursuant to which PCEC will provide the Trust with

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certain operating and informational services relating to the Conveyed Interests in exchange for a monthly fee. The monthly fee will be an amount equal to $83,333.33, which fee will change on an annual basis commencing on April 1, 2013, based on changes to the CPI. The PCEC operating and services fee will be $1,000,000 for the twelve months ending March 31, 2013.

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INFORMATION ABOUT

PACIFIC COAST ENERGY COMPANY LP

(PCEC)

The trust units are not interests in or obligations of PCEC

Business and Properties of PCEC

PCEC is a privately held Delaware limited partnership formed on June 15, 2004 as Breitburn Energy Company, L.P. to engage in the production and development of oil and natural gas from properties located in California.

The Underlying Properties were acquired through various transactions prior to 2005 and are located in the Santa Maria and Los Angeles Basins in California. After giving pro forma effect to the conveyance of the Conveyed Interests to the trust, the offering of the trust units contemplated by this prospectus and the application of the net proceeds as described in Use of Proceeds, as of December 31, 2011, PCEC would have had total assets of $283.5 million and total liabilities of $92.6 million. For an explanation of the pro forma adjustments, please read Financial Statements of Pacific Coast Energy Company LP Unaudited Pro Forma Financial Statements Introduction.

As of December 31, 2011, PCEC held interests in approximately 276 gross (215 net) producing wells, and had proved reserves of approximately 34.1 MMBoe.

Management of PCEC

PCEC has no employees, executive officers or directors, and is managed by its general partner, PCEC (GP) LLC, or PCEC GP, the executive officers of which are employees of BreitBurn Management Company LLC, or BreitBurn Management. PCEC GP is managed by the Board of Representatives of Pacific Coast Energy Holdings LLC, or PCEH, the sole member of PCEC GP. Set forth in the table below are the names, ages and titles of the Board of Representatives of PCEH and the executive officers of PCEC GP. In August 2008, PCEH acquired its interest in PCEC by acquiring PCEC s general and limited partners.

Name	Age	Title
Randall H. Breitenbach	51	Chief Executive Officer and Board Representative
Halbert S. Washburn	52	President and Board Representative
Mark L. Pease	55	Executive Vice President and Chief Operating Officer
James G. Jackson	47	Executive Vice President and Chief Financial Officer
Gregory C. Brown	60	Executive Vice President and General Counsel
Chris E. Williamson	54	Vice President Operations
W. Jackson Washburn	49	Vice President Real Estate
Bruce D. McFarland	55	Treasurer and Secretary
Lawrence C. Smith	58	Controller
Howard Hoffen	48	Board Representative
Gregory D. Myers	41	Board Representative
V. Frank Pottow	48	Board Representative

Randall H. Breitenbach is a co-founder of PCEC and has been PCEH s Chief Executive Officer since March 2012 and is a member and the Chairman of the Board of Representatives of PCEH, the sole member of PCEC GP. He also served as the Co-Chief Executive Officer of PCEH from August 2008 to March 2012 and as the Co-Chief Executive Officer of BreitBurn GP, LLC, or BreitBurn GP, which is the General Partner of

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BreitBurn Energy Partners L.P., a publicly traded oil and gas partnership, since March 2006. In addition, Mr. Breitenbach has been the President of BreitBurn GP since April 2010 and from March 2006 until April 2010, he served as Co-Chief Executive Officer and a Director of BreitBurn GP. In December 2011, he was re-appointed to the Board of BreitBurn GP. Mr. Breitenbach currently serves as a Trustee and is Chairman of the governance and nominating committee for Hotchkis and Wiley Funds, which is a mutual funds company. He has also served as a board member, including Chairman of the Board of Directors, of the Stanford University Petroleum Investments Committee. Mr. Breitenbach holds both a B.S and M.S. degree in Petroleum Engineering from Stanford University and an M.B.A. from Harvard Business School.

Mr. Breitenbach has a distinguished career as an executive in the oil and gas industry. His more than 25 years of management experience in the oil and gas industry provides Mr. Breitenbach with a keen understanding of PCEC s operations and an in-depth knowledge of its industry. Mr. Breitenbach s experience serving on the boards of directors of both public and private companies allows him to provide PCEH s Board of Representatives with a variety of perspectives on corporate governance and other issues.

Halbert S. Washburn is a co-founder of PCEC and has been PCEH s President since March 2012 and is a member of the Board of Representatives of PCEH, the sole member of PCEC GP. Mr. Washburn served as the Co-Chief Executive Officer of PCEH from August 2008 to March 2012. In addition, Mr. Washburn has been the Chief Executive Officer of BreitBurn GP since April 2010. He served as Co-Chief Executive Officer and a Director of BreitBurn GP from March 2006 until April 2010 and was the Chairman of the Board from July 2008 to April 2010. In December 2011, he was re-appointed to the Board of BreitBurn GP. Mr. Washburn is the brother of W. Jackson Washburn, PCEH s Vice President Real Estate. Since December 2005, Mr. Washburn has served as a member of the Board of Directors and the audit and compensation committees of Rentech, Inc., a publicly traded alternative fuels company, and since June 2011, has served as the Chairman of the Rentech, Inc. Board. Since July 2011, Mr. Washburn has also served as a Director of Rentech Nitrogen GP, LLC, the general partner of Rentech Nitrogen Partners, L.P., a publicly traded limited partnership involved in the production of nitrogen fertilizer. He has been a member of the California Independent Petroleum Association since 1995 and served as Chairman of the executive committee of the Board of Directors from 2008 to 2010. He has also served as a board member, including Chairman of the Board of Directors, of the Stanford University Petroleum Investments Committee. Mr. Washburn holds a B.S. degree in Petroleum Engineering from Stanford University.

Mr. Washburn has a distinguished career as an executive in the oil and gas industry. His more than 25 years of management experience in the oil and gas industry provides Mr. Washburn with a keen understanding of PCEC s operations and an in-depth knowledge of its industry. Mr. Washburn s experience serving on boards of directors of both public and private companies allows him to provide PCEH s Board of Representatives with a variety of perspectives on corporate governance and other issues.

Mark L. Pease has been PCEH s Chief Operating Officer since August 2008. Mr. Pease has been the Chief Operating Officer and an Executive Vice President of BreitBurn GP since December 2007. Prior to joining BreitBurn GP, Mr. Pease served as Senior Vice President, E&P Technology & Services for Anadarko Petroleum Corporation, an international and domestic oil and natural gas exploration and production company, or Anadarko. Mr. Pease joined Anadarko in 1979 as an engineer, and served as Senior Vice President, North America from 2004 to 2006 and as Vice President, U.S. Onshore and Offshore from 2002 to 2004. Mr. Pease obtained a B.S. in Petroleum Engineering from the Colorado School of Mines.

James G. Jackson has been PCEH s Chief Financial Officer since August 2008. Mr. Jackson has also served as the Chief Financial Officer of BreitBurn GP since July 2006 and as an Executive Vice President since October 2007. Since June 2011, Mr. Jackson has served as a member of the Board of Directors of Niska Gas Storage Partners LLC, a publicly traded master limited partnership that owns and operates natural gas storage assets in North America. Before joining BreitBurn GP, Mr. Jackson served as Managing Director of the Global Markets and Investment Banking Group for Merrill Lynch & Co., a global financial management and investment banking firm. Mr. Jackson joined Merrill Lynch in 1992 and was elected Managing Director in 2001. Previously,

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Mr. Jackson was a Financial Analyst with Morgan Stanley & Co. from 1986 to 1989 and was an Associate in the Mergers and Acquisitions Group of the Long-Term Credit Bank of Japan from 1989 to 1990. Mr. Jackson obtained a B.S. in Business Administration from Georgetown University and an M.B.A. from the Stanford Graduate School of Business.

Gregory C. Brown has been PCEH s General Counsel and an Executive Vice President since August 2008. Mr. Brown joined BreitBurn GP in December 2006 and currently serves as its General Counsel and Executive Vice President. Before joining BreitBurn GP, Mr. Brown was a partner at Bright and Brown, a law firm specializing in energy and environmental law that he co-founded in 1981. Mr. Brown earned a B.A. degree from George Washington University, with Honors, Phi Beta Kappa, and a J.D. from the University of California, Los Angeles. Mr. Brown was Mayor and has served on the City Council of the City of La Canada Flintridge from 2003 to 2011.

Chris E. Williamson has been PCEH s Vice President of Operations since August 2008. Mr. Williamson has also served as a Senior Vice President of BreitBurn GP since January 2008 and previously served as Vice President of Operations since March 2006. Before joining BreitBurn GP, Mr. Williamson worked for five years as a petroleum engineer for Macpherson Oil Company. Prior to his position with Macpherson, Mr. Williamson worked at Shell Oil Company for eight years holding various positions in Engineering and Operations. Mr. Williamson holds a B.S. in Chemical Engineering from Purdue University.

W. Jackson Washburn has been PCEH s Vice President of Real Estate since August 2008. Mr. Washburn has served as the Senior Vice President Business Development of BreitBurn GP since April 2009 and previously served as Vice President Business Development since August 2007. Mr. Washburn is the brother of Halbert S. Washburn, PCEH s President. Since joining PCEC s predecessor in 1992, Mr. Washburn has served in a variety of capacities, and has served as President of PCEC Land Company, LLC, a subsidiary of PCEC, since 2000. Mr. Washburn obtained a B.A. in Psychology from Wake Forest University.

Bruce D. McFarland has been PCEH s Treasurer since August 2008. Mr. McFarland has served as the Vice President and Treasurer of BreitBurn GP since March 2006 and as a Vice President since April 2009. Mr. McFarland previously served as the Chief Financial Officer of BreitBurn GP from March 2006 through June 2006. Since joining PCEC s predecessor in 1994, Mr. McFarland served as Controller and Treasurer for more than five years. Before joining PCEC s predecessor, Mr. McFarland served as Division Controller of IT Corporation and worked at PriceWaterhouseCoopers as a Certified Public Accountant. Mr. McFarland obtained a B.S. in Civil Engineering from the University of Florida and an M.B.A. from the University of California, Los Angeles.

Lawrence C. Smith has been PCEH s Controller since August 2008. Mr. Smith has also served as the Controller of BreitBurn GP since June 2006 and as a Vice President since April 2009. Before joining BreitBurn GP, Mr. Smith served as the Corporate Accounting Compliance and Implementation Manager of Unocal Corporation, which was an oil and natural gas production and exploration development company, or Unocal, from 2000 through May 2006. Mr. Smith worked at Unocal from 1981 through May 2006 and held various managerial positions in Unocal s accounting and finance organizations. Mr. Smith obtained a B.B.A. in Accounting from the University of Houston, an M.B.A. from the University of California, Los Angeles, and is a Certified Public Accountant.

Howard Hoffen has been a member of the Board of Representatives of PCEH since August 2008. Mr. Hoffen has been the Chairman and Chief Executive Officer of Metalmark Capital LLC, or Metalmark, since its formation in 2004. Prior to joining Metalmark, from 2001 to 2004, he was the Chairman and CEO of Morgan Stanley Capital Partners and a Managing Director of Morgan Stanley & Co., since 1997. Additionally, Mr. Hoffen serves as a Director of EnerSys, Union Drilling and several private companies. Mr. Hoffen received a B.S. from Columbia University and an M.B.A from Harvard Business School.

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PCEC believes that Mr. Hoffen s many years of investing experience, as well as his in-depth knowledge of the oil and gas industry generally, and PCEC in particular, provide him with the necessary skills to be a member of the Board of Representatives of PCEH.

Gregory D. Myers has been a member of the Board of Representatives of PCEH since August 2008. Mr. Myers is a Managing Director at Metalmark and was a founding member in 2004. From 1998 to 2004, Mr. Myers was a senior investment professional at Morgan Stanley Capital Partners. Mr. Myers also serves as a Director of Union Drilling and several private companies. Mr. Myers received a B.S. and B.A. from The University of Pennsylvania and an M.B.A. from Harvard Business School.

PCEC believes that Mr. Myers many years of investing experience, as well as his in-depth knowledge of the oil and gas industry generally, and PCEC in particular, provide him with the necessary skills to be a member of the Board of Representatives of PCEH.

V. Frank Pottow has been a member of the Board of Representatives of PCEH since August 2008. Since 2009, Mr. Pottow has been a Managing Director and co-founder of GCP Capital Partners, LLC. From 2002 to 2009 Mr. Pottow was a Managing Director and member of the investment committee of Greenhill Capital Partners, LLC, the global merchant banking business of Greenhill & Co., Inc. From 1997 to 2002, he was a co-founder and Managing Director of SG Capital Partners. Additionally, Mr. Pottow was a Principal of Odyssey Partners, L.P. from 1992 to 1996. Mr. Pottow also serves as a board member of several private companies. Mr. Pottow obtained a B.S. from The Wharton School of The University of Pennsylvania and received an M.B.A. from Harvard Business School.

PCEC believes that Mr. Pottow s many years of investing experience, as well as his in-depth knowledge of the oil and gas industry generally, and PCEC in particular, provide him with the necessary skills to be a member of the Board of Representatives of PCEH.

Compensation Discussion and Analysis

Executive Summary

The trust was formed in January 2012 and does not have any executive officers, managers or employees. As such, the trust has not paid or accrued any obligations with respect to compensation or benefits for its managers or executive officers. The trust does not expect to pay any salaries, bonuses or equity awards to such executive officers or managers. In addition, PCEC does not have any executive officers, managers or employees. The trust and PCEC are managed by PCEC GP.

The executive officers of PCEC GP who perform services on behalf of the trust and/or PCEC are employed directly by BreitBurn Management. BreitBurn Management will make compensation decisions for, and pay compensation directly to, the executive officers who perform services on behalf of PCEC and the trust.

Administrative Services from BreitBurn Management

BreitBurn Management will not receive any management fees or other compensation for the services its provides to the trust, but will be entitled to a monthly fixed fee and reimbursement for actual third-party and direct expenses incurred on behalf of PCEC and its affiliates (including the trust) in accordance with the terms of the Second Amended and Restated Administrative Services Agreement, or PCEC Administrative Services Agreement, which PCEC expects to amend in April 2012 to extend the term through August 31, 2014 and revise the monthly fee. Currently, the fixed monthly fee is renegotiated annually based on budgeted costs and a time allocation study but will become fixed at $700,000 through August 31, 2014 following execution of the Third Amended and Restated Administrative Services Agreement, which PCEC expects to enter into in connection with the closing of this offering. During fiscal year 2011, this monthly fee was approximately $481,000. Please read PCEC Administrative Services Agreement for more information.

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BreitBurn Management does not allocate any portion of the compensation paid to the executive officers to PCEC or the trust. Other than annual bonuses, which are paid directly by PCEC, BreitBurn Management pays all compensation and benefits directly to the executive officers that perform services for PCEC and/or the trust. The executive officers do not participate in any long-term incentive compensation programs related to the services they perform for PCEC or the trust, and have not participated in the PCEH Long-Term Incentive Plan adopted by PCEH in 2009.

Annual Incentive Compensation

PCEC provides eligible employees of BreitBurn Management who perform services on behalf of PCEC and/ or the trust, including executive officers, with short-term incentive awards in the form of discretionary annual cash bonuses. The annual bonuses, which are determined by the Board of Representatives of PCEH, are purely discretionary and are paid directly by PCEC generally during the first quarter of each fiscal year. The Board of Representatives of PCEH does not rely on pre-determined company performance goals or metrics, but instead determines individual bonus amounts at the end of each fiscal year based on a comprehensive assessment of all reasonably available information, including the applicable executive officer s performance and PCEC s operational and financial performance. The Board of Representatives of PCEH believes that this process incentivizes the executive officers to maximize overall performance rather than to focus on only a few determinative factors.

Following the closing of this offering, the Board of Representatives of PCEH will maintain ultimate discretion in assessing the individual performance of executive officers and the financial and operational performance of PCEC and determining whether such performance warrants the payment of any annual cash bonuses and, if applicable, the amounts of such cash bonuses.

For the year ended December 31, 2011, the Board of Representatives of PCEH awarded the following cash bonuses to Chief Executive Officer of PCEC GP, the President of PCEC GP, the Chief Financial Officer of PCEC GP, and the three other executive officers of PCEC GP who received the highest cash bonuses from PCEC GP:

Name	2011 Annual Bonus
Randall H. Breitenbach	$185,938
Halbert S. Washburn	$185,938
Mark L. Pease	$118,125
James G. Jackson	$111,563
Gregory C. Brown	$111,563
W. Jackson Washburn	$60,156

Litigation

PCEC is not a party to any material legal action.

Indemnification

Subject to specified limitations, each partner, officer and employee will not be liable, responsible or accountable in damages or otherwise to PCEC or its members for, and PCEC will indemnify and hold harmless each member, manager and officer from, any costs, expenses, losses or damages (including attorneys fees and expenses, court costs, judgments and amounts paid in settlement) incurred by reason of such person being a member, manager or officer of PCEC.

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Management s Discussion and Analysis of Financial Condition and Results of Operations of PCEC

You should read the following discussion of the financial condition and results of operations of PCEC in conjunction with the historical consolidated financial statements of PCEC and related notes included elsewhere in this prospectus.

Factors that Significantly Affect PCEC s Results

PCEC s revenue, cash flow from operations and future growth depend substantially on factors beyond its control, such as economic, political and regulatory developments and competition from producers of alternative sources of energy. Oil and natural gas prices have historically been volatile and may fluctuate widely in the future. Sustained periods of low prices for oil or natural gas could materially and adversely affect PCEC s financial position, results of operations and ability to access capital, as well as the quantities of oil and natural gas that it can economically produce.

Like all businesses engaged in the production and exploration of oil and natural gas, PCEC faces the challenge of natural production declines. As initial reservoir pressures are depleted, oil and natural gas production from a given well decreases. Thus, an oil and gas exploration and production company depletes part of its asset base with each unit of oil or natural gas it produces. PCEC attempts to reduce this natural decline by undertaking field development programs and by implementing secondary recovery techniques. PCEC s ability to make development expenditures to maintain production from existing reserves and to add reserves through development drilling is dependent on their capital resources and can be limited by many factors.

Results of Operations

References in this section to production, sales or realized gains or losses on derivative instruments attributable to oil include minimal amounts attributable to natural gas liquids.

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Comparison of Results of Operations for the Years Ended December 31, 2011, 2010 and 2009

The table below summarizes certain of the results of operations and period-to-period comparisons attributable to PCEC s operations for the periods indicated.

Thousands of dollars, except as indicated	Twelve Months Ended December 31, 2011	2010	2009	Increase / Decrease % 2011-2010	2010-2009
Total production (MBoe)	1,215	1,129	1,291	8%	-13%
Oil (MBoe)	1,171	1,086	1,240	8%	-12%
Natural gas (MMcf)	264	259	305	2%	-15%
Average daily production (Boe/d)	3,328	3,094	3,538	8%	-13%
Sales volumes (MBoe)	1,215	1,129	1,291	8%	-13%
Average realized sales price (per Boe)[(a)]					
Including realized gain (loss) on derivative instruments	$ 94.18	$ 81.76	$ 71.78	15%	14%
Oil (per Boe)[(a)]	96.92	84.46	74.40	15%	14%
Natural gas (per Mcf)	3.55	2.31	1.29	54%	79%
Excluding realized gain (loss) on derivative instruments	$ 87.92	$ 68.09	$ 51.76	29%	32%
Oil (per Boe)	90.41	69.99	53.22	29%	32%
Natural gas (per Mcf)	3.55	3.45	2.72	3%	27%
Oil and natural gas sales	$ 106,809	$ 76,898	$ 66,842	39%	15%
Realized gains on commodity derivative instruments[(b)]	23,488	15,426	25,844	52%	-40%
Unrealized gains (losses) on commodity derivative instruments[(b)]	(20,321)	(30,261)	(86,388)	-33%	-65%
Lease operating expenses and processing fees	36,227	33,175	38,651	9%	-5%
Production and property taxes[(c)]	3,110	2,352	3,766	32%	-38%
Total operating expenses	39,337	35,527	38,651	11%	-8%
Lease operating expenses pre taxes per Boe	$ 29.82	$ 29.37	$ 27.02	2%	9%
Production and property taxes per Boe	2.56	2.08	2.92	23%	-29%
Total lease operating expenses per Boe	32.38	31.45	29.93	3%	5%

(a) Excludes the effect of the early termination of hedge contracts monetized in October 2011 for $16,078.
(b) Includes the effect of early termination of hedge contracts monetized in October 2011 for $16,078.
(c) Includes ad valorem and severance taxes.

The variances in PCEC s results of operations were due to the following components:

Production. For the year ended December 31, 2011 compared to the year ended December 31, 2010, production volumes increased by 86 MBoe, or 8%, primarily due to higher oil volumes from PCEC s Orcutt Diatomite properties reflecting the positive results from the expansion project.

For the year ended December 31, 2010 compared to the year ended December 31, 2009, production volumes decreased by 162 MBoe, or 13%, primarily due to lower oil volumes from PCEC s conventional Orcutt and Orcutt Diatomite properties.

Revenues. Total oil and natural gas sales revenues increased by $29.9 million for the year ended December 31, 2011 compared to the year ended December 31, 2010. For 2011 compared to 2010, higher commodity prices increased total oil and natural gas sales revenues by approximately $24.1 million and higher sales volumes increased total sales revenues by approximately $5.8 million. Realized gains from commodity

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derivative instruments were $23.5 million in 2011 compared to realized gains of $15.4 million in 2010. Higher realized gains in 2011 were primarily due to a gain of $16.1 million on hedge contracts terminated in the fourth quarter of 2011 partially offset by higher crude oil prices in 2011 as compared to 2010. Unrealized losses from commodity derivative instruments for the year ended December 31, 2011 were $20.3 million reflecting the impact of hedge contract terminations during the fourth quarter of 2011. Unrealized losses from commodity derivative instruments for the year ended December 31, 2010 were $30.3 million reflecting the increase in crude oil futures prices during 2010.

Total oil and natural gas sales revenues increased by $10.0 million for the year ended December 31, 2010 compared to the year ended December 31, 2009. Realized gains from commodity derivative instruments were $15.4 million in 2010 compared to realized gains of $25.8 million in 2009. Unrealized losses from commodity derivative instruments for the year ended December 31, 2010 were $30.3 million reflecting an increase in crude oil prices during 2010. Unrealized losses from commodity derivative instruments for the year ended December 31, 2009 were $86.4 million reflecting the increase in crude oil futures prices during 2009. For 2010 compared to 2009, higher commodity prices increased total oil and natural gas sales revenues by approximately $18.4 million and lower sales volumes decreased total sales revenues by approximately $8.4 million.

Operating expenses. Pre-tax lease operating expenses, including expenses for regional operating management and processing fees, for the year ended December 31, 2011 totaled $36.2 million, or $29.82 per Boe, which was 2% higher per Boe than 2010. The increase was primarily due to higher service costs during 2011 compared to 2010 due to higher crude oil prices.

Production and property taxes for the year ended December 31, 2011 totaled $3.1 million, or $2.56 per Boe, which was 23% higher per Boe than the year ended December 31, 2010. The per Boe increase in production and property taxes compared to 2010 reflects higher tax assessment valuations in 2011.

Pre-tax lease operating expenses, including district expenses and processing fees, for the year ended December 31, 2010 totaled $33.2 million, or $29.37 per Boe, which was 9% higher per Boe than 2009. The decrease was primarily due to lower service costs during 2010 compared to 2009.

Production and property taxes for the year ended December 31, 2010 totaled $2.4 million, or $2.08 per Boe, which was 29% lower per Boe than the year ended December 31, 2009. The per Boe decrease in production and property taxes compared to 2009 reflects lower tax assessment valuations in 2010.

The variances in PCEC s other financial results included the following:

Depletion, depreciation and amortization. Depletion, depreciation and amortization (DD&A) expense totaled $20.9 million, or $17.21 per Boe, for the year ended December 31, 2011, a decrease of approximately 27% per Boe from the year ended December 31, 2010. The decrease in DD&A compared to 2010 was primarily due to the DD&A rate adjustments in 2011 related to higher reserves at PCEC s conventional Orcutt properties and additions related to new wells at PCEC s Orcutt Diatomite properties.

DD&A expense totaled $26.7 million, or $23.67 per Boe, for the year ended December 31, 2010, a decrease of approximately 28% per Boe from the year ended December 31, 2009. The decrease in DD&A compared to 2009 was primarily due to the effect that higher 2010 commodity prices had on DD&A rates.

Dry Hole Costs. Dry hole costs of $2.8 million for the year ended December 31, 2010 are primarily attributable to the unsuccessful portion of a West Pico well.

General and administrative expenses. PCEC s G&A expenses totaled $8.7 million and $6.5 million in 2011 and 2010, respectively. This included $0.7 million and $0.2 million, respectively, in unit-based compensation expense related to employee incentive plans. Unit-based compensation expense in 2011 does not include compensation expense associated with performance-based units as we cannot predict with certainty when or if a realization event will occur (see Note 10 to PCEC financial statements for an explanation of what may constitute a realization event). If a realization event had occurred on December 31, 2011, we would have recognized approximately $1.0 million in unit-based compensation expense associated with performance based awards and approximately $0.6 million of unit-based compensation expense associated with unvested time-based awards. For 2011, G&A expenses, excluding unit-based compensation, were $8.0 million, which was $1.7 million higher than 2010. The increase was primarily due to higher fees under the PCEC Administrative Services Agreement negotiated with BreitBurn Management, higher annual bonus plan costs and higher legal and other professional fees.

G&A expenses totaled $6.5 million and $5.8 million in 2010 and 2009, respectively. This included $0.2 million and $0.2 million, respectively, in unit-based compensation expense related to employee incentive plans. For 2010, G&A expenses, excluding unit-based compensation, were $6.3 million, which was $0.8 million higher than 2009. The increase was primarily due to higher short-term incentive compensation expense.

Interest and other financing costs, net. PCEC s interest expense totaled $6.9 million for the year ended December 31, 2011, a decrease of $1.8 million from 2010. This decrease in interest expense was primarily attributable to lower average debt balances under PCEC s credit facility and lower interest rates for the year ended December 31, 2011.

PCEC s interest expense totaled $8.7 million for the year ended December 31, 2010, a decrease of $0.8 million from 2009. This decrease in interest expense was primarily attributable to a lower average debt balance under PCEC s credit facility and lower interest rates for the year ended December 31, 2010.

Loss on interest rate derivative instruments. PCEC had realized losses of $1.5 million for the year ended December 31, 2011, compared to realized losses of $1.6 million for the year ended December 31, 2010, and unrealized gains of $1.4 million for the year ended December 31, 2011 compared to unrealized gains of $0.3 million for the year ended December 31, 2010, relating to its interest rate swaps. PCEC had no outstanding interest swaps remaining at December 31, 2011.

PCEC had realized losses of $1.6 million for the year ended December 31, 2010, compared to realized losses of $1.5 million for the year ended December 31, 2009, and unrealized gains of $0.3 million for the year ended December 31, 2010 compared to unrealized gains of $0.4 million for the year ended December 31, 2009, relating to its interest rate swaps.

Liquidity and Capital Resources

PCEC s primary sources of liquidity are cash generated from operations and amounts available under its revolving credit facility. Historically, PCEC s primary uses of cash have been for its operating expenses, capital expenditures and unit repurchases. As market conditions have permitted, PCEC has also engaged in asset sale transactions.

Credit Facilities

On August 26, 2008 PCEC entered into a four year, $400.0 million second amended and restated revolving credit facility with Wells Fargo Bank, N.A., and a syndicate of banks (the Second Amended and Restated Credit Agreement). The initial borrowing base of the Second Amended and Restated Credit Agreement was $125.0 million. As of December 31, 2011 and December 31, 2010 our borrowing base was $131.0 million and $115.0 million, respectively. In January 2012, our borrowing base was increased to $150.0 million. Under the Second Amended and Restated Credit Agreement, borrowings were allowed to be used for (i) payment of a portion of the 2008 acquisition of the interests in PCEC, (ii) standby letters of credit, (iii) working capital purposes, (iv) general company purposes and (v) certain permitted acquisitions and payments enumerated by the credit facility. Borrowings under the Second Amended and Restated Credit Agreement are secured by first-priority liens on and security interests in substantially all of PCEC s and certain of its subsidiaries assets, representing not less than 80% of the total value of PCEC s oil and gas properties.

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The Second Amended and Restated Credit Agreement contains (i) financial covenants, including leverage, current assets and interest coverage ratios, and (ii) customary covenants, including restrictions on PCEC s ability to: (a) incur additional indebtedness; (b) make certain investments, loans or advances; (c) make distributions to unitholders or repurchase units if aggregated letters of credit and outstanding loan amounts exceed 90% of its borrowing base; (d) make dispositions; or (e) enter into a merger or sale of its property or assets, including the sale or transfer of interests in its subsidiaries.

The events that constitute an Event of Default (as defined in the Second Amended and Restated Credit Agreement) include: (i) payment defaults; (ii) misrepresentations; (iii) breaches of covenants; (iv) cross-default and cross-acceleration to certain other indebtedness; (v) adverse judgments against PCEC in excess of a specified amount; (vi) changes in management or control; (vii) loss of permits; (viii) failure to perform under a material agreement; (ix) certain insolvency events; (x) assertion of certain environmental claims; and (xi) occurrence of a material adverse effect. At December 31, 2011, December 31, 2010 and December 31, 2009, PCEC was in compliance with the credit facility s covenants.

On August 26, 2008, PCEC also entered into a five year, $60.0 million second lien term loan with Wells Fargo Energy Capital, Inc. and other lenders (the Second Lien Credit Agreement). PCEC used the funds to pay for a portion of the 2008 acquisition of the interests in PCEC.

As of December 31, 2011 and 2010, PCEC had $74.0 million and $82.0 million, respectively, in debt outstanding under the Second Amended and Restated Credit Agreement, that will mature on August 24, 2012, and $30.0 million and $60.0 million, respectively, in debt outstanding under the Second Lien Credit Agreement at each date, which will mature on February 24, 2013. PCEC plans to enter into the Third Amended and Restated Credit Agreement immediately prior to the closing of this offering.

Cash Flows

Operating activities. PCEC s cash flow from operating activities for the year ended December 31, 2011 was $71.9 million compared to $40.5 million in the year ended December 31, 2010. Included in cash flow from operating activities for the year ended December 31, 2011 were net proceeds of $16.1 million from the termination of commodity derivative contracts. In addition, cash flow from operating activities was higher than the year ended December 31, 2010 due the net effect of higher commodity prices and higher production volumes partially offset by higher operating costs and expenses.

PCEC s cash flow from operating activities for the year ended December 31, 2010 was $40.5 million compared to $35.6 million in the year ended December 31, 2009, primarily reflecting changes in net assets and liabilities.

Investing activities. Net cash used in investing activities for the year ended December 31, 2011 was $31.3 million, which was spent predominantly on drilling and completions primarily for PCEC s Orcutt Diatomite and conventional Orcutt properties. Net cash used by investing activities for the year ended December 31, 2010 was $40.2 million, which was spent predominantly on drilling and completions primarily for PCEC s Orcutt Diatomite, West Pico and conventional Orcutt properties.

Net cash used in investing activities for the year ended December 31, 2009 was $18.0 million, spent predominantly on drilling and completions primarily for PCEC s conventional Orcutt and Orcutt Diatomite properties.

Financing activities. Net cash used in financing activities for the year ended December 31, 2011 was $39.3 million compared to $1.5 million for the year ended December 31, 2010. PCEC decreased its net borrowings of debt by approximately $38.0 million in the year ended December 31, 2011 compared to a reduction of debt of $1.0 million in the year ended December 31, 2010.

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Net cash used in financing activities for the year ended December 31, 2010 was $1.5 million compared to $16.4 million for the year ended December 31, 2009. PCEC decreased its net borrowings of debt by approximately $1.0 million in 2010 compared to a reduction of debt of $12.5 million in 2009.

Tax Payment

On March 12, 2012, PCEC paid $9.2 million to the individual partners of PCEH, the sole member of PCEC s general partner. The payment is intended to enable PCEH s individual partners to pay their U.S. federal, state and local tax liabilities relating to their taxable income in the partnership.

Contractual Obligations

In addition to the credit facility described above, PCEC entered into the PCEC Administrative Services Agreement with BreitBurn Management described under PCEC Administrative Services Agreement. PCEC also reimburses BreitBurn Management monthly for all third party direct costs, long term incentive plan (LTIP) costs and other direct costs relating to the performance of services for PCEC. PCEC expects to enter into the Third Amended and Restated Administrative Services Agreement in connection with the closing of this offering, which will extend the term through August 31, 2014.

Off-Balance Sheet Arrangements

PCEC did not have any off-balance sheet arrangements as of December 31, 2011.

Commitments

The following table summarizes PCEC s financial contractual obligations as of December 31, 2011. Some of these contractual obligations are reflected in the balance sheet, while others are disclosed as future obligations under accounting principles generally accepted in the United States.

			Payments Due by Year				
Thousands of dollars	**2012**	**2013**	**2014**	**2015**	**2016**	**After**	**Total**
Revolving credit facility	$ 74,000	$	$	$	$	$	$ 74,000
Credit facility commitment fees	77						77
Second lien credit agreement		30,000					30,000
Estimated interest payments	4,160	2,803					6,963
Vehicle and equipment leases	135	96	58	15	4		308
Asset retirement obligation						22,300	22,300
Total	$ 78,372	$ 32,899	$ 58	$ 15	$ 4	$ 22,300	$ 133,648

Critical Accounting Policies and Estimates

The discussion and analysis of PCEC s financial condition and results of operations is based upon its consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires PCEC to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenue and expenses, and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. PCEC evaluates its estimates and assumptions on a regular basis. PCEC bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in the preparation of PCEC s financial statements. Below, PCEC has

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provided expanded discussion of the more significant accounting policies, estimates and judgments. PCEC believes these accounting policies reflect the more significant estimates and assumptions used in preparation of its financial statements. Please read the notes to the financials of PCEC included elsewhere in this prospectus for a discussion of additional accounting policies and estimates made by its management.

Successful Efforts Method of Accounting

PCEC accounts for oil and gas properties using the successful efforts method. Under this method of accounting, leasehold acquisition costs are capitalized. Subsequently, if proved reserves are found on unproved property, the leasehold costs are transferred to proved properties. Under this method of accounting, costs relating to the development of proved areas are capitalized when incurred.

Depletion, depreciation and amortization of producing oil and gas properties is recorded based on units of production. Unit rates are computed for unamortized drilling and development costs using proved developed reserves and for unamortized leasehold costs using all proved reserves. FASB accounting standards require that acquisition costs of proved properties be amortized on the basis of all proved reserves, developed and undeveloped, and that capitalized development costs (wells and related equipment and facilities) be amortized on the basis of proved developed reserves.

Geological, geophysical and dry hole costs on oil and gas properties relating to unsuccessful exploratory wells are charged to expense as incurred.

Oil and gas properties are reviewed for impairment when facts and circumstances indicate that their carrying value may not be recoverable. PCEC assesses impairment of capitalized costs of proved oil and gas properties by comparing net capitalized costs to estimated undiscounted future net cash flows using expected prices. If net capitalized costs exceed estimated undiscounted future net cash flows, the measurement of impairment is based on estimated fair value, which would consider estimated future discounted cash flows. For purposes of performing an impairment test, the undiscounted cash flows are forecast using five-year NYMEX forward strip prices at the end of the period and escalated thereafter at 2.5%. For impairment charges, the associated proved properties expected future net cash flows are discounted using a rate of approximately 10%. Unproved properties are assessed for impairment along with proved properties and if considered impaired are charged to expense when such impairment is deemed to have occurred. PCEC did not record an impairment charge in 2011, 2010 or 2009. Price declines may in the future result in impairment charges, which could have a material adverse effect on PCEC s results of operations in the period incurred.

Property acquisition costs are capitalized when incurred.

PCEC capitalizes interest costs to oil and gas properties on expenditures made in connection with certain projects such as drilling and completion of new oil and natural gas wells and major facility installations. Interest is capitalized only for the period that such activities are in progress. Interest is capitalized using a weighted average interest rate based on PCEC s outstanding borrowings. These capitalized costs are included with intangible drilling costs and amortized using the units of production method. During 2011, interest of $0.2 million was capitalized and included in PCEC s capital expenditures. During 2010, interest of less than $0.1 million was capitalized and included in PCEC s capital expenditures. PCEC had no capitalized interest for 2009 and 2008.

Oil and Gas Reserve Quantities

The estimates of PCEC s proved reserves are based on the quantities of oil and gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Annually, Netherland, Sewell & Associates, Inc. prepare reserve and economic evaluations of all of PCEC s properties on a well-by-well basis.

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Estimated proved reserves and their relation to estimated future net cash flows impact PCEC s depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. PCEC prepares its disclosures for reserve estimates, and the projected cash flows derived from these reserve estimates, in accordance with SEC guidelines. The independent engineering firm described above adheres to the same guidelines when preparing its reserve report. The accuracy of the reserve estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgments of the individuals preparing the estimates.

Because these estimates depend on many assumptions, all of which may substantially differ from future actual results, reserve estimates will be different from the quantities of oil and natural gas that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may justify, positively or negatively, material revisions to the estimate of proved reserves.

PCEC s estimates of proved reserves materially impact depletion expense. If the estimates of proved reserves decline, the rate at which PCEC records depletion expense will increase, reducing future net income. Such a decline may result from lower market prices, which may make it uneconomical to drill for and produce higher cost fields. In addition, a decline in proved reserve estimates may impact the outcome of PCEC s assessment of oil and gas producing properties for impairment. For example, if the SEC prices used for PCEC s December 31, 2010 reserve report had been $10.00 less per Bbl and $1.00 less per MMBtu, respectively, then the standardized measure of PCEC s estimated proved reserves as of December 31, 2010 would have decreased by approximately $137.2 million, from $661.5 million to $524.3 million.

Any material inaccuracies in these reserve estimates or underlying assumptions could materially affect the quantities and present value of PCEC s reserves.

Asset Retirement Obligations

Estimated asset retirement obligation (ARO) costs are recognized when the asset is placed in service and are amortized over proved reserves using the units of production method. PCEC estimates asset retirement costs using existing regulatory requirements and anticipated future inflation rates. Projecting future ARO cost estimates is difficult as it involves the estimation of many variables such as economic recoveries of future oil and gas reserves, future labor and equipment rates, future inflation rates, and PCEC s credit adjusted risk free interest rate. Because of the intrinsic uncertainties present when estimating asset retirement costs as well as asset retirement settlement dates, PCEC s ARO estimates are subject to ongoing volatility.

Derivative Instruments

PCEC periodically uses derivative financial instruments to achieve more predictable cash flow from its oil and natural gas production by reducing its exposure to price fluctuations. Currently, these instruments include swaps, collars and options. Additionally, PCEC may use derivative financial instruments in the form of interest rate swaps to mitigate interest rate exposure. PCEC accounts for these activities pursuant to FASB accounting standards that require derivative instruments (including certain derivative instruments embedded in other contracts) be recorded at fair market value and be included in the balance sheet as assets or liabilities. The accounting for changes in the fair market value of a derivative instrument depends on the intended use of the derivative instrument and the resulting designation, which is established at the inception of a derivative instrument. PCEC is required to formally document, at the inception of a hedge, the hedging relationship and its risk management objective and strategy for undertaking the hedge, including identification of the hedging instrument, the hedged item or transaction, the nature of the risk being hedged, the method that will be used to assess effectiveness and the method that will be used to measure hedge ineffectiveness of derivative instruments that receive hedge accounting treatment. PCEC does not account for its derivative instruments as cash flow hedges for financial accounting purposes and is recognizing changes in the fair value of its derivative instruments immediately in net income.

New Accounting Pronouncements

In May 2011, the Financial Accounting Standards Board (FASB) issued an Accounting Standards Update (ASU) to improve comparability between U.S. GAAP and International Financial Reporting Standards (IFRS) fair value measurement and disclosure requirements. This amendment changes the wording used to describe many of the requirements in U.S. GAAP for measuring fair value and for disclosing information about fair value measurements, particularly for Level 3 fair value measurements. For many of the requirements, the FASB does not intend for the amendments to result in a change in the application of the fair value measurement and disclosure requirements. Some of the amendments clarify the FASB s intent about the application of existing fair value measurement requirements. Other amendments change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements. This ASU is effective for interim and annual periods beginning after December 15, 2011. This ASU requires prospective application. PCEC does not expect the adoption of this ASU to have a material impact on its financial position, results of operations or cash flows.

In June 2011, the FASB issued an ASU to improve comparability, consistency, and transparency of financial reporting and to increase the prominence of items reported in other comprehensive income. The amendment requires that components of other comprehensive income be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. For public entities, this ASU is effective for fiscal years beginning after December 15, 2011 and for interim periods within those years. This ASU requires retrospective application. Additionally, in December 2011, the FASB issued an ASU which indefinitely defers the requirement to present reclassification adjustments out of accumulated other comprehensive income by component in both the statement in which net income is presented and the statement in which other comprehensive income is presented. During the deferral period, the existing requirements in U.S. GAAP for the presentation of reclassification adjustments must continue to be followed. PCEC does not present components of other comprehensive income, and, therefore, PCEC does not expect the provisions of this amendment to have an impact on its financial position, results of operations or cash flows.

In December 2011, the FASB issued an ASU which requires companies to disclose information about financial instruments that have been offset and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. Companies will be required to provide both net (offset amounts) and gross information in the notes to the financial statements for relevant assets and liabilities that are offset. This update is effective on or after January 1, 2013 and must be applied retrospectively. PCEC does not expect the adoption of this ASU to have a material impact on its financial position, results of operations or cash flows.

Quantitative and Qualitative Disclosures About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about PCEC s potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how PCEC views and manages its ongoing market risk exposures. All of PCEC s market risk sensitive instruments were entered into for purposes other than speculative trading.

Crude Oil Price Risk

Due to the historical volatility of crude oil and natural gas prices, PCEC has entered into various derivative instruments to manage exposure to volatility in the market price of crude oil and natural gas to achieve more

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predictable cash flows. PCEC uses swaps, collars and options for managing risk relating to crude oil prices. All contracts are settled with cash and do not require the delivery of physical volumes to satisfy settlement. While this strategy may result in PCEC having lower revenues than it would otherwise have if it had not utilized these instruments in times of higher oil and natural gas prices, PCEC believes that the resulting reduced volatility of prices and cash flow is beneficial. While PCEC s crude oil price risk management program is intended to reduce its exposure to crude oil prices and assist with stabilizing cash flow and distributions, to the extent PCEC has hedged a significant portion of its expected production and the cost for goods and services increases, PCEC s margins would be adversely affected. To the extent PCEC has hedged a significant portion of its expected production and actual production is lower than expected or the costs of goods and services increase, PCEC s profitability would be adversely affected. The use of derivatives also involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts.

	Year 2012	Year 2013	Year 2014	Year 2015
Oil Positions:				
Fixed Price Swaps:				
Hedged Volume (Bbls/d)	1,700	1,950	1,658	1,399
Average Price ($/Bbl)	$ 103.14	$ 94.76	$ 91.80	$ 91.63
Collars:				
Hedged Volume (Bbls/d)	650	325	325	325
Average Floor Price ($/Bbl)	$ 110.00	$ 100.00	$ 100.00	$ 100.00
Average Ceiling Price ($/Bbl)	$ 127.10	$ 115.70	$ 116.50	$ 117.25
Floors:				
Hedged Volume (Bbls/d)	750	500		
Average Floor Price ($/Bbl)	$ 70.00	$ 70.00		
Premiums ($/Bbl)	$ 4.63	$ 4.94		
Total:				
Hedged Volume (Bbls/d)	3,100	2,775	1,983	1,724
Average Price ($/Bbl)	$ 96.56	$ 90.91	$ 93.14	$ 93.21
Gas Positions:				
Fixed Price Swaps:				
Hedged Volume (MMBtu/d)	250			
Average Price ($/MMBtu)	$ 7.36			

PCEC s oil commodity derivative instruments provide for monthly settlement based on the differential between the agreement price and the actual NYMEX WTI crude oil price.

PCEC does not currently designate any of its derivative instruments as hedges for financial accounting purposes. In order to qualify for hedge accounting, the relationship between the hedging instrument and the hedged item must be highly effective in achieving the offset of changes in cash flows attributable to the hedged risk both at the inception of the contract and on an ongoing basis. Hedge effectiveness must be measured, at minimum, on a quarterly basis. Hedge accounting must be discontinued prospectively when a hedge instrument is no longer considered to be highly effective. Many of PCEC s commodity derivative instruments would not qualify for hedge accounting due to the ineffectiveness created by variability in its price discounts or differentials.

PCEC sells the majority of the oil production under contracts using market sensitive pricing. The price received by PCEC for the oil production 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. PCEC s Los Angeles Basin crude oil is generally medium gravity crude. Because of its proximity to the extensive Los Angeles refinery market, it has historically traded at only a minor discount to NYMEX WTI and more recently it has traded at a premium to NYMEX WTI, as WTI and Brent oil prices have recently diverged. PCEC s Santa

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Maria Basin crude oil is a mix of medium and heavy crude and trades on average at a discount to NYMEX WTI. In October 2011, in order to improve the effectiveness of its hedge portfolio, PCEC terminated certain crude oil fixed price swaps at NYMEX WTI prices for a total net gain of $16.1 million and entered into new crude oil fixed price swaps for the same volumes and periods at IPE Brent prices.

During 2011, the average premium for PCEC s crude oil production relative to NYMEX WTI benchmark prices per Bbl was $12.19. During 2010, the average discounts PCEC received for its crude oil production relative to NYMEX WTI benchmark prices per Bbl were $2.50.

All derivative instruments are recorded on the balance sheet at fair value. Fair value is generally determined based on the difference between the fixed contract price and the underlying market price at the determination date, and/or confirmed by the counterparty. Changes in the fair value of PCEC s commodity derivatives that were not designated as a hedge were recorded in gain (loss) on commodity derivative instruments, net on the consolidated statements of operations, as a loss of $20.3 million for 2011 and as a loss of $30.3 million for 2010.

Interest Rate Risk

PCEC is subject to interest rate risk associated with loans under its credit facility that bear interest based on floating rates. PCEC currently does not designate any of its interest rate derivatives as hedges for financial accounting purposes. As of December 31, 2011, short-term and long-term debt outstanding under PCEC s credit facility was $104.0 million. As of December 31, 2011, PCEC s LIBOR based debt was $74.0 million. In order to mitigate its interest rate exposure, PCEC has entered into various interest rate swaps to fix a portion of floating LIBOR based debt under its credit facility. For the year ended December 31, 2011, PCEC s interest rate swaps covered $70.0 million of its LIBOR based debt. PCEC had no interest rate swaps at December 31, 2011.

Changes in Fair Value

The fair value of PCEC s outstanding oil and gas commodity derivative instruments at December 31, 2011 was a net liability of approximately $2.0 million. The fair value of PCEC s outstanding oil and gas commodity derivative instruments at December 31, 2010 was a net asset of approximately $17.6 million.

As of December 31, 2011, with a $5.00 per Bbl increase in the price of oil, and a corresponding $1.00 per Mcf change in the natural gas price, PCEC s net commodity derivative instrument liability would have decreased by approximately $15.0 million. As of December 31, 2011, with a $5.00 per Bbl decrease in the price of oil, and a corresponding $1.00 per Mcf change in the natural gas price, PCEC s net commodity derivative instrument liability would have decreased by approximately $15.0 million.

Price risk sensitivities were calculated by assuming across-the-board increases in price of $5.00 per Bbl for oil and $1.00 per Mcf for natural gas regardless of term or historical relationships between the contractual price of the instruments and the underlying crude oil price. In the event of actual changes in prompt month prices equal to the assumptions, the fair value of PCEC s derivative portfolio would typically change by less than the amounts given due to lower volatility in out-month prices.

PCEC had no outstanding interest rate derivative instruments at December 31, 2011. The fair value of PCEC s interest rate derivative instruments at December 31, 2010 was $1.4 million.

Changes in derivative instruments since December 31, 2011

On January 17, 2012, PCEC entered into crude oil fixed price swap contracts for 500 Bbl/d for the period January 1, 2014 to December 31, 2014 at $99.90 per Bbl and 800 Bbl/d for the period January 1, 2015 to December 31, 2015 at $96.45 per Bbl.

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On March 6, 2012, we terminated a crude oil option contract for 200 Bbl/d for the period from January 1, 2012 to December 31, 2012 at NYMEX WTI $70.00 per Bbl at a cost of $0.2 million and also terminated crude oil fixed price swaps at a cost of $12.4 million as follows:

Period	Average IPE Brent $/Bbl	Volume Bbl/d
April 1, 2012 to December 31, 2012	$ 102.68	1,250
January 1, 2013 to December 31, 2013	99.20	1,125
January 1, 2014 to March 31, 2014	95.55	1,050

Concurrently with the terminations, we entered into a new crude oil fixed price swap for 2,000 Bbl/day for the period April 1, 2012 to March 31, 2014 at IPE Brent $115.00 per Bbl at a cost of $3.0 million.

Description of the PCEC Limited Partnership Agreement

The following is a summary of the material provisions of the Amended and Restated Limited Partnership Agreement of PCEC, or the Partnership Agreement . This summary may not contain all of the information that is important to you. A copy of the Partnership Agreement has been filed as an exhibit to the registration statement. Please read Where You Can Find More Information. Terms used but not defined elsewhere in this prospectus shall have the meanings set forth in the Partnership Agreement.

Organization and Duration

PCEC will remain in existence until dissolved in accordance with the Partnership Agreement. Please read Dissolution.

Business

The Partnership Agreement limits the business of PCEC to the acquisition, development and operation of oil and gas properties and taking all such other actions incidental to the foregoing.

Distribution of Available Cash

Within 45 calendar days after the end of each month the general partner shall cause PCEC to distribute cash available for distribution to the partners in proportion to their respective percentage interests. In addition, PCEC shall make a tax liability distribution if the aggregate amount of cash distributed to a partner is less than such partner s minimum tax liability distribution, as determined on a quarterly and annual basis.

All cash funds of PCEC available for distribution to its partners will be after giving effect to the obligation of PCEC to pay to the trust 80% of the net profits from the sale of oil and natural gas production from proved reserves on the Underlying Properties as of December 31, 2011 and either 25% of the net profits from the sale of oil and natural gas production from the remaining Underlying Properties (the Remaining Properties) or 7.5% of the proceeds (free of any production or development costs but bearing its proportionate share of production and property taxes) from the Remaining Properties located on PCEC s Orcutt properties, pursuant to the Conveyed Interests. For a more detailed description of the determination of net profits, please read Computation of Net Profits and Royalties.

Management of PCEC

The Partnership Agreement provides that the general partner of PCEC shall generally have sole and complete charge and management of all the affairs and business of PCEC and may take all such actions as the general partner deems necessary or appropriate to accomplish the purposes and direct the affairs of PCEC.

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PCEC (GP) LLC serves as the general partner. BreitBurn Management operates PCEC s assets and performs other administrative services such as accounting, corporate development, finance, land administration, legal and engineering in accordance with the PCEC Administrative Services Agreement dated August 26, 2008. The general partner has no employees. BreitBurn Management provides administrative services to the general partner pursuant to the PCEC Administrative Services Agreement. Please read PCEC Administrative Services Agreement below. In exchange for the services provided, PCEC pays BreitBurn Management a monthly fee for indirect expenses and also charges PCEC for all direct expenses including incentive plan costs and direct payroll and administrative costs related to the PCEC properties and operations. Currently, the monthly fee is contractually based on an annual projection of anticipated time spent by each employee who provides services to PCEC during the ensuing year and is subject to renegotiation annually by the parties during the term of the agreement but will become fixed at $700,000 through August 31, 2014 following execution of the Third Amended and Restated Administrative Services Agreement. In 2011, the monthly fee was approximately $481,000.

The general partner is restricted from taking certain actions without the unanimous approval of the class A limited partners. These actions include the following:

- engage in any transaction (subject to certain exceptions) that will result in the holders of a majority of voting partnership interests prior to the transaction holding less than a majority of the voting partnership interests following the transaction or any transfer of majority ownership,

- alter or extend the purpose of PCEC set forth in the Partnership Agreement or amend or restate the Partnership Agreement in a manner that impairs or otherwise adversely affects the rights and interests of PCEC,

- reorganize, dissolve, wind up or liquidate PCEC, or file any voluntary bankruptcy petition,

- cause PCEC to change its form of legal entity or to be conducted in any manner such that it would be treated as an association taxable as a corporation for U.S. federal income tax purposes,

- enter into or participate in any transaction (subject to certain exceptions) with Provident Energy Trust (Provident) or its affiliates,

- engage in any act in contravention of the Partnership Agreement or that would cause any limited partner to lose its limited liability or otherwise make a limited partner liable for the obligations of PCEC, or

- engage in any acquisition of assets that is reasonably expected at the time such acquisition is consummated to reduce the value per interest at any time during the 180 days following the consummation of such acquisition below the value per interest immediately prior to the consummation of such acquisition.

Limited Liability

The limited partners of PCEC are not liable for the debts, liabilities, contracts or other obligations of PCEC under the Partnership Agreement. Moreover, PCEC agrees to indemnify and hold harmless the general partner, the limited partners, their affiliates, and all officers, agents and personnel of PCEC and/or of the general partner to the full extent permitted by law from and against any and all losses, claims, demands, costs, damages, liabilities, expenses of any nature (including reasonable attorneys fees and disbursements and other costs of litigation, whether pending or threatened), judgments, fines, settlements and other amounts arising out of or incidental to the business of PCEC, if: (i) such party acted in good faith and in a manner such person believed to be within the scope of such Indemnitee s authority and in, or not contrary to, the best interests of PCEC, and (ii) such party s conduct did not constitute fraud, bad faith, gross negligence, willful misconduct or a breach of the Partnership Agreement. Any indemnification shall be satisfied out of the assets of PCEC as a PCEC expense, and the limited partners are not subject to personal liability by reason of the indemnification provisions. The

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expenses incurred by such party in defending any claim, demand, action, suit or proceeding shall be advanced by PCEC prior to the final disposition of such claim, demand, action, suit or proceeding upon receipt by PCEC of a written commitment by such party to repay such amount if it shall be determined that such Indemnitee is not entitled to be indemnified.

Contracts With Affiliates

PCEC may enter into various contracts and agreements with the general partner, limited partners and with their respective affiliates.

Rights of the Partners

The general partner shall cause to be kept (and made available to each partner), at the principal place of business of PCEC, or at such other location as the general partner deems appropriate, full and proper ledgers, other books of account, and records of all receipts and disbursements, other financial activities, and the internal affairs of PCEC for at least the current and past four fiscal years. Partners and their agents and representatives may, for purposes reasonably related to their Interests, examine and request copies of the books and records of PCEC to which a Limited Partner would be entitled in accordance with the Delaware Revised Uniform Limited Partnership Act (the DRULPA) during business hours upon notice to the general partner at the principal offices of PCEC.

In addition, within 90 days following the end of each fiscal year of PCEC or as soon as reasonably practicable thereafter, each partner shall be entitled to receive (i) financial statements of PCEC prepared on the basis of the accrual method of accounting in accordance with generally accepted accounting principles and which have been certified as to compliance with generally accepted accounting principles by an officer of the general partner and (ii) the information necessary to complete such partner s tax returns, including a copy of PCEC s federal and state Schedule K-1s, and any other documents or reports reasonably requested by a partner to which a limited partner would be entitled in accordance with the DRULPA.

Prior to transferring its interest in PCEC, a limited partner must obtain the prior written consent of the general partner and all other limited partners, unless the transfer is made to such limited partner s affiliate and such affiliate agrees in writing to be bound by the Partnership Agreement, in which case such consent would not be required. In addition, no transfer may be made by a limited partner if such transfer: (i) causes a termination of PCEC for federal or state, if applicable, income tax purposes, (ii) causes PCEC to cease to be classified as a partnership for federal or state income tax purposes (subject to certain exceptions), (iii) requires the registration of such transferred interest pursuant to any applicable federal or state securities laws, (iv) causes PCEC to become a Publicly Traded Partnership (as defined in Sections 469(k)(2) or 7704(b) of the Code) that is treated as an association taxable as a corporation, (v) subjects PCEC to regulation under the Investment Company Act of 1940, the Investment Advisers Act of 1940 or the Employee Retirement Income Security Act of 1974, each as amended, (vi) violates any applicable laws, (vii) be made to a person who lacks the legal right, power or capacity to own such interests or (viii) results in PCEC not receiving written instruments that are in form reasonably satisfactory to the partners.

Amendment of the Partnership Agreement

The Partnership Agreement may be amended only by the unanimous written consent of the general partner and all class A limited partners.

Dissolution

PCEC will continue as a limited partnership until terminated under the Partnership Agreement. PCEC will dissolve: (1) upon the written consent of the general partner and Class A Limited Partners holding a majority of the Class A Interests; (2) upon the dissolution, bankruptcy or termination of the general partner and failure of another partner to carry on the business of PCEC and become the general partner; or (3) at any time that there are no partners, unless the business of PCEC is continued in accordance with the DRULPA.

Liquidation and Termination

Upon dissolution of PCEC, a liquidator or liquidating committee approved by the general partner, which such person or group may include the general partner or any limited partner or officer, will wind up the affairs and make final distribution. Such liquidator shall continue to operate the properties of PCEC with all of the power and authority of the general partner necessary or appropriate to liquidate the assets of PCEC and apply the proceeds of the liquidation as described in the Partnership Agreement.

PCEC Administrative Services Agreement

On August 26, 2008, PCEC entered into the PCEC Administrative Services Agreement with BreitBurn Management, a wholly owned subsidiary of BreitBurn Energy Partners L.P., or BBEP, pursuant to which BreitBurn Management manages the operations of PCEC and provides administrative services such as accounting, corporate development, finance, land, legal and engineering to PCEC. Pursuant to the PCEC Administrative Services Agreement, PCEC pays BreitBurn Management a negotiated monthly fixed fee for indirect costs, including general and administrative costs, relating to the performance of services relating to the business of PCEC.

Currently, the monthly fee is contractually based on an annual projection of anticipated time spent by each employee who provided services to both PCEC and BBEP during the ensuing year. The monthly fee in effect for 2009 was $500,000. The monthly fee for 2010 was approximately $456,000. In 2011, the monthly fee for indirect costs charged to PCEC was $481,000. For January through March of 2012, the monthly fee was $571,000. The changes in the monthly fee for indirect expenses in 2010 and in 2011 were primarily due to the shift of certain indirect expenses to direct expenses and changes in the time allocated to PCEC in each year.

Pursuant to the terms of the Third Amended and Restated PCEC Administrative Services Agreement, the monthly fee will be fixed at $700,000 through the end of the term. PCEC also expects to pay a one-time fee of $250,000 to BBEP in connection with an amendment to the PCEC Administrative Services Agreement.

PCEC expects to enter into the Third Amended and Restated PCEC Administrative Services Agreement in connection with the closing of this offering to extend the term through August 31, 2014. The Agreement also will provide PCEC with an unconditional right to terminate upon 180 days notice and will include provisions outlining the terms on which PCEC may hire BreitBurn Management employees following termination of the agreement. In the absence of written notice delivered to the other party by either party to the agreement of its intention not to continue under the terms of the agreement, given no later than 180 days before August 31, 2014, and each successive anniversary thereof, the term of the agreement will be extended for one additional calendar year until either or both parties have given notice of their intention to terminate.

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INDEX TO FINANCIAL STATEMENTS OF PACIFIC COAST ENERGY COMPANY LP

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Report of Independent Registered Public Accounting Firm

To the Partners of Pacific Coast Energy Company LP

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, cash flows and changes in partners equity present fairly, in all material respects, the financial position of Pacific Coast Energy Company LP and its subsidiaries at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Partnership s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Los Angeles, California

March 5, 2012

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Pacific Coast Energy Company LP and Subsidiaries

Consolidated Balance Sheets

Thousands of dollars	December 31, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash	$ 1,380	$ 92
Accounts receivable, net	13,428	11,080
Derivative instruments (Note 8)	1,482	9,380
Prepaid expenses	115	98
Total current assets	16,405	20,650
Equity investments (Note 5)	35,067	36,454
Property, plant and equipment		
Oil and gas properties	421,207	385,939
Non-oil and gas assets	9,149	9,141
	430,356	395,080
Accumulated depletion and depreciation	(94,241)	(74,506)
Net property, plant and equipment	336,115	320,574
Other long-term assets		
Derivative instruments (Note 8)	409	11,235
Other long-term assets	4,682	4,402
Total assets	$ 392,678	$ 393,315
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	7,628	9,090
Derivative instruments (Note 8)	866	3,113
Short-term debt (Note 6)	74,000	
Related party payables (Note 4)	3,159	3,360
Revenue and royalties payable	3,970	3,490
Other current liabilities	744	2,155
Total current liabilities	90,367	21,208
Long-term debt (Note 6)	30,000	142,000
Asset retirement obligation (Note 7)	22,300	16,189
Derivative instruments (Note 8)	3,059	1,275
Other long-term liabilities	899	1,198
Total liabilities	146,625	181,870
Commitments and Contingencies (Note 11)		
Equity:		
Partners equity (Note 12)	246,053	211,445
Total equity	246,053	211,445

Total liabilities and equity	$ 392,678	$ 393,315

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

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Pacific Coast Energy Company LP and Subsidiaries

Consolidated Statements of Operations

Thousands of dollars, except per unit amounts	Year Ended December 31, 2011	2010	2009
Revenues and other income items:			
Oil, natural gas and natural gas liquid sales	$ 106,809	$ 76,898	$ 66,842
Gain (loss) on commodity derivative instruments, net (Note 8)	3,167	(14,835)	(60,544)
(Loss) earnings from equity affiliates (Note 5)	(1,182)	108	(190)
Other revenue, net	1,988	634	370
Total revenues and other income items	110,782	62,805	6,478
Operating costs and expenses:			
Operating costs	39,337	35,527	38,651
Depletion, depreciation and amortization	20,905	26,732	42,300
Dry hole costs		2,752	
General and administrative expenses	8,757	6,492	5,819
Total operating costs and expenses	68,999	71,503	86,770
Operating income (loss)	41,783	(8,698)	(80,292)
Interest and other financing costs, net	6,947	8,669	9,534
Loss on interest rate derivative instruments (Note 8)	94	1,310	1,158
Other expense (income), net	115	133	(4)
Total other expenses, net	7,156	10,112	10,688
Net income (loss)	$ 34,627	$ (18,810)	$ (90,980)
Basic and diluted net income (loss) per unit	$ 0.17	$ (0.09)	$ (0.46)
Weighted average number of units used to calculated basic and diluted net income per unit	198,882	198,882	198,882

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

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Pacific Coast Energy Company LP and Subsidiaries

Consolidated Statements of Cash Flows

	Year Ended December 31,		
Thousands of dollars	**2011**	**2010**	**2009**
Cash flows from operating activities			
Net income (loss)	$ 34,627	$ (18,810)	$ (90,980)
Adjustments to reconcile to cash flow for operating activities:			
Depletion, depreciation and amortization	20,905	26,732	42,300
Dry hole costs		2,752	
Unit-based compensation expense	690	204	243
Unrealized loss on derivative instruments	18,946	29,988	86,007
Loss from equity affiliates, net	1,387	32	310
Other	525	35	1,266
Changes in net assets and liabilities:			
Accounts receivable and other assets	(4,421)	(1,570)	(1,733)
Related party payables	(201)	280	(1,159)
Accounts payable and other liabilities	(544)	833	(685)
Net cash provided by operating activities	71,914	40,476	35,569
Cash flows from investing activities			
Capital expenditures	(31,305)	(40,213)	(17,994)
Net cash used by investing activities	(31,305)	(40,213)	(17,994)
Cash flows from financing activities			
Proceeds from the issuance of debt	158,000	68,500	64,500
Repayments of debt	(196,000)	(69,500)	(77,000)
Bank overdraft	(347)	347	(2,879)
Debt issuance costs	(265)	(110)	(362)
Payments made on behalf of PCEH	(709)	(690)	(642)
Net cash used in financing activities	(39,321)	(1,453)	(16,383)
Net increase (decrease) in cash	1,288	(1,190)	1,192
Cash beginning of period	92	1,282	90
Cash end of period	$ 1,380	$ 92	$ 1,282

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

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Pacific Coast Energy Company LP and Subsidiaries

Consolidated Statements of Changes in Partners Equity

Thousands of dollars	Total
Balance, December 31, 2008	**$ 322,125**
Net loss	(90,980)
Incentive compensation issued by PCEH	239
Accounts due from PCEH	(642)
Balance, December 31, 2009	**$ 230,742**
Net loss	(18,810)
Incentive compensation issued by PCEH	204
Accounts due from PCEH	(691)
Balance, December 31, 2010	**$ 211,445**
Net income	34,627
Incentive compensation issued by PCEH	690
Accounts due from PCEH	(709)
Balance, December 31, 2011	**$ 246,053**

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

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Notes to the Consolidated Financial Statements

Note 1. Organization and Operations

On August 26, 2008, members of senior management, in their individual capacities, together with Metalmark Capital Partners LLC (Metalmark), Greenhill Capital Partners LLC (Greenhill) and Wells Fargo Central Pacific Holdings, Inc. (Wells Fargo), formed Pacific Coast Energy Holdings LLC (PCEH), formerly known as BreitBurn Energy Holdings LLC, in order to acquire Pacific Coast Energy Company LP (PCEC or the Partnership), formerly known as BreitBurn Energy Company L.P. References in this report to we, our, us or like terms refer to the Partnership. The Partnership is engaged in the acquisition, development and production of oil and natural gas properties in California.

The Partnership was originally formed on June 15, 2004 when Provident Energy Trust (Provident), an open-end unincorporated investment trust created under the laws of Alberta, Canada, acquired the Partnership s predecessor at that time, BreitBurn Energy Company LLC (BEC LLC) and converted it to a Delaware limited partnership. Provident held its interests indirectly through two wholly-owned subsidiaries, Pro LP Corp. (Pro LP) and Pro GP Corp (Pro GP).

PCEH acquired a 96.0% indirect interest in the Partnership from Provident, and senior management contributed the remaining indirect interests. Metalmark invested $100 million, Greenhill invested $75 million, Wells Fargo invested $5 million, and senior management invested $0.95 million of cash in addition to their contribution of their existing interests in the Partnership. The purchase price of PCEH s acquisition of its indirect interest in the Partnership was $294 million in cash and $10 million in the form of a subordinated unsecured promissory note.

As a result of the acquisition, the Partnership is owned indirectly by an affiliate of Metalmark, with a 51.25% interest, affiliates of Greenhill, with a 38.44% interest, Wells Fargo, with a 2.56% interest, and members of senior management, including interests owned by BreitBurn Energy Company, with a combined 7.75% interest. The members of senior management who invested in the Partnership have the right to earn additional interests in the Partnership s profits based on certain rates of return on investment the Partnership achieves. At the closing of the acquisition, members of senior management were appointed as officers of PCEH, the sole member of PCEC (GP) LLC (PCEC GP), formerly known as BEH (GP) LLC, the Partnership s general partner, and as officers of PCEC GP.

In connection with the acquisition, we also entered into a Second Amended and Restated Administrative Services Agreement (the Administrative Services Agreement) with BreitBurn Management Company LLC (BreitBurn Management), a subsidiary of BreitBurn Energy Partners L.P. (BBEP) to manage our properties. BBEP is an independent oil and gas master limited partnership that is also managed by BreitBurn Management. Halbert Washburn and Randall Breitenbach, our Co-Chief Executive Officers, are Chief Executive Officer and President, respectively, of the general partner of BBEP. Because of this relationship, BBEP and its subsidiaries are considered related parties. See Note 4 Related Party Transactions for a discussion of the Administrative Services Agreement. We also entered into an Omnibus Agreement with BBEP detailing rights with respect to business opportunities and providing BBEP with a right of first offer with respect to the sale of our assets.

We are also the general partner of BreitBurn Energy Partners I, L.P. (BEP I), a Texas limited Partnership that owns a 96% working interest in the East Coyote and Sawtelle producing oil and gas fields located in the Los Angeles Basin in Southern California. BEP I is engaged in the exploitation, development and production of oil and gas properties in California. We have a 1% general partner interest in BEP I. BBEP owns the remaining 99% limited partner interest in BEP I. We also own a direct 4% working interest in the East Coyote and Sawtelle oil and gas fields.

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Note 2. Summary of Significant Accounting Policies

Principles of consolidation

The consolidated financial statements include our accounts and the accounts of our wholly owned subsidiaries. Investments in affiliated companies with a 20% or greater ownership interest, and in which we do not have control, are accounted for on the equity basis. Investments in which we own greater than 50% interest and in which we have control are consolidated. The effects of all intercompany transactions have been eliminated.

Basis of presentation

The financial statements are prepared in conformity with U.S. generally accepted accounting principles. The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. The financial statements are based on a number of significant estimates including fair value of derivative instruments, equity based compensation and oil and gas reserve quantities, which are the basis for the calculation of depletion, depreciation, amortization, asset retirement obligations and impairment of oil and gas properties.

Business segment information

We report in one segment because our oil and gas operating areas have similar economic characteristics. We acquire, exploit, develop and produce oil and natural gas in California. Corporate management administers all properties as a whole rather than as discrete operating segments. Operational data is tracked by area; however, financial performance is measured as a single enterprise and not on an area-by-area basis. Allocation of capital resources is employed on a project-by-project basis across our entire asset base to maximize profitability without regard to individual areas.

Revenue recognition

Revenues associated with sales of crude oil and natural gas are recognized when title passes from us to our customers. Revenues from properties in which we have an interest with other partners are recognized on the basis of our working interest (entitlement method of accounting). We generally market 100 percent of our natural gas production from our operated properties and pay our partners for their working interest shares of natural gas production sold. As a result, we have no natural gas producer imbalance positions.

Accounts receivable

Our accounts receivable are primarily from purchasers of crude oil and natural gas and counterparties to our financial instruments. Crude oil receivables are generally collected within 30 days after the end of the month. Natural gas receivables are generally collected within 60 days after the end of the month. We review all outstanding accounts receivable balances and record a reserve for amounts that we expect will not be fully recovered. Actual balances are not applied against the reserve until substantially all collection efforts have been exhausted. At December 31, 2011 and 2010, the allowance for doubtful accounts receivable was less than $0.1 million.

Property, plant and equipment

Oil and gas properties

We follow the successful efforts method of accounting. Lease acquisition and development costs (tangible and intangible) incurred relating to proved oil and gas properties are capitalized. Delay and surface rentals are charged to expense as incurred. Dry hole costs incurred on exploratory wells are expensed. In 2010, we recorded $2.8 million in exploratory dry hole costs related to the unsuccessful portion of the drilling of deeper zones in our West Pico properties. Dry hole costs associated with developing proved fields are capitalized. Geological and geophysical costs related to exploratory operations are expensed as incurred.

Upon sale or retirement of proved properties, the cost thereof and the accumulated depletion, depreciation and amortization (DD&A) are removed from the accounts and any gain or loss is recognized in the statement of operations. Maintenance and repairs are charged to operating expenses. DD&A of proved oil and gas properties, including the estimated cost of future abandonment and restoration of well sites and associated facilities, are computed on a property-by-property basis and recognized using the units-of-production method net of any anticipated proceeds from equipment salvage and sale of surface rights.

We capitalize interest costs to oil and gas properties on expenditures made in connection with drilling and completion of new oil and natural gas wells. Interest is capitalized only for the period that such activities are in progress. Interest is capitalized using a weighted average interest rate based on our outstanding borrowings. These capitalized costs are included with intangible drilling costs and amortized using the units of production method. For the year ended December 31, 2011, interest of $0.2 million was capitalized and included in our capital expenditures. For the year ended December 31, 2010, interest of less than $0.1 million was capitalized. We had no capitalized interest for 2009.

Non-oil and gas assets

Buildings and non-oil and gas assets are recorded at cost and depreciated using the straight-line method over their estimated useful lives, which range from three to 30 years.

Oil and natural gas reserve quantities

Reserves and their relationship to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion are made prospectively with changes to reserve estimates. We disclose reserve estimates, and the projected cash flows derived from these reserve estimates, in accordance with the Securities and Exchange Commission (the SEC) guidelines. The independent engineering firm adheres to the SEC definitions when preparing their reserve report.

Asset retirement obligations

We have significant obligations to plug and abandon oil and natural gas wells and related equipment at the end of oil and natural gas production operations. The fair value of a liability for an asset retirement obligation (ARO) is recorded when there is a legal obligation associated with the retirement of a tangible long-lived asset and the liability can be reasonably estimated. Over time, changes in the present value of the liability are accreted and expensed. The capitalized asset costs are depreciated over the useful lives of the corresponding asset. Recognized liability amounts are based upon future retirement cost estimates and incorporate many assumptions such as: (1) expected economic recoveries of crude oil and natural gas, (2) time to abandonment, (3) future inflation rates and (4) the risk free rate of interest adjusted for our credit costs. Future revisions to ARO estimates will impact the present value of existing ARO liabilities and corresponding adjustments will be made to the capitalized asset retirement costs balance.

Impairment of assets

Long-lived assets with recorded values that are not expected to be recovered through future cash flows are written down to estimated fair value. A long-lived asset is tested for impairment when events or circumstances indicate that its carrying value may not be recoverable. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of

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the asset. If the carrying value exceeds the sum of the undiscounted cash flows, an impairment loss equal to the amount by which the carrying value exceeds the fair value of the asset is recognized. Fair value is generally determined from estimated discounted future net cash flows. For purposes of performing an impairment test, the undiscounted cash flows are forecast using five-year NYMEX forward strip prices at the end of the period and escalated thereafter at 2.5%. For impairment charges, the associated property s expected future net cash flows are discounted using a rate of approximately 10%. Reserves are calculated based upon reports from third-party engineers adjusted for acquisitions or other changes occurring during the year as determined to be appropriate in the good faith judgment of management.

We assess our long-lived assets for impairment generally on a field-by-field basis where applicable. We did not record an impairment charge for the years ended December 31, 2011, 2010 and 2009.

Debt issuance costs

The costs incurred to obtain financing have been capitalized. Debt issuance costs are amortized using the straight-line method over the term of the related debt. Use of the straight-line method does not differ materially from the effective interest method of amortization.

Equity-based compensation

We have no employees and are managed by PCEC GP, our general partner, the executive officers of which are employees of BreitBurn Management. We account for our incentive compensation plans applying measurement guidance applicable to awards to non-employees.

See Note 10 for a description of outstanding PCEH compensation plans for BreitBurn Management s employees.

Fair market value of financial instruments

The carrying amount of our cash, accounts receivable, accounts payable, and accrued expenses approximate their respective fair value due to the relatively short term of the related instruments. The carrying amount of long-term debt approximates fair value; however, changes in the credit markets at year-end may impact our ability to enter into future credit facilities on similar terms.

Concentration of credit risk

We maintain our cash accounts primarily with a single bank and invest cash in money market accounts, which we believe to have minimal risk. As operator of jointly owned oil and gas properties, we sell oil and gas production to U.S. large domestic refiners and pay vendors on behalf of joint owners for oil and gas services. We periodically monitor our major purchasers credit ratings. For the years ended December 31, 2011, 2010 and 2009, ConocoPhillips accounted for 97% of net sales. ConocoPhillips purchase of production from the Orcutt properties is pursuant to a long-term sales contract between ConocoPhillips and PCEC, and its purchase of production from the Sawtelle and West Pico properties is pursuant to a month-to-month contract.

Derivatives

We recognize all of our derivative instruments as assets or liabilities on our balance sheet and measure those instruments at fair value. The accounting treatment of changes in fair value is dependent upon whether or not a derivative instrument is designated as a hedge and if so, the type of hedge. We do not designate any of our derivatives as hedges for accounting purposes. Gains and losses on derivative instruments not designated as hedges are currently included in earnings. The resulting cash flows are reported as cash from operating activities.

Accounting standards define fair value, establish a framework for measuring fair value and expand disclosures about fair value measurements. Fair value measurement is based upon a hypothetical transaction to

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sell an asset or transfer a liability at the measurement date, considered from the perspective of a market participant that holds the asset or owes the liability. The objective of fair value measurement is to determine the price that would be received in selling the asset or transferring the liability in an orderly transaction between market participants at the measurement date. If there is an active market for the asset or liability, the fair value measurement shall represent the price in that market whether the price is directly observable or otherwise obtained using a valuation technique.

Income taxes

We and most of our subsidiaries are partnerships or limited liability companies treated as partnerships for federal and state income tax purposes. Essentially all of our taxable income or loss, which may differ considerably from the net income or loss reported for financial reporting purposes, is passed through to the federal and state income tax returns of our partners. As such, no federal or state income taxes for these entities have been provided for in the accompanying financial statements.

Earnings per unit

Weighted average units outstanding for computing basic earnings the years ended December 31, 2011, 2010 and 2009 were:

	Year Ended December 31, 2011	Year Ended December 31, 2010	Year Ended December 31, 2009
Units outstanding basic and diluted	198,881,535	198,881,535	198,881,535

Environmental expenditures

We review, on an annual basis, our estimates of the cleanup costs of various sites. When it is probable that obligations have been incurred, and where a reasonable estimate of the cost of compliance or remediation can be determined, the applicable amount is accrued. For other potential liabilities, the timing of accruals coincides with the related ongoing site assessments. We do not discount any of these liabilities. At December 31, 2011 and 2010, we did not have any probable environmental costs.

Note 3. Accounting Standards

In May 2011, the FASB issued an Accounting Standards Update (ASU) to improve comparability between U.S. GAAP and International Financial Reporting Standards (IFRS) fair value measurement and disclosure requirements. This amendment changes the wording used to describe many of the requirements in U.S. GAAP for measuring fair value and for disclosing information about fair value measurements, particularly for Level 3 fair value measurements. For many of the requirements, the FASB does not intend for the amendments to result in a change in the application of the fair value measurement and disclosure requirements. Some of the amendments clarify the FASB s intent about the application of existing fair value measurement requirements. Other amendments change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements. This ASU is effective for interim and annual periods beginning after December 15, 2011. This ASU requires prospective application. We do not expect the adoption of this ASU to have a material impact on our financial position, results of operations or cash flows.

In June 2011, the FASB issued an ASU to improve comparability, consistency, and transparency of financial reporting and to increase the prominence of items reported in other comprehensive income. The amendment requires that components of other comprehensive income be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. For public entities, this ASU is effective for fiscal years beginning after December 15, 2011 and for interim periods within those years. This

ASU requires retrospective application. Additionally, in December 2011, the FASB issued an ASU which indefinitely defers the requirement to present reclassification adjustments out of accumulated other comprehensive income by component in both the statement in which net income is presented and the statement in which other comprehensive income is presented. During the deferral period, the existing requirements in U.S. GAAP for the presentation of reclassification adjustments must continue to be followed. We do not present components of other comprehensive income, and, therefore, we do not expect the provisions of this amendment to have an impact on our financial position, results of operations or cash flows.

In December 2011, the FASB issued an ASU which requires companies to disclose information about financial instruments that have been offset and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. Companies will be required to provide both net (offset amounts) and gross information in the notes to the financial statements for relevant assets and liabilities that are offset. This update is effective on or after January 1, 2013 and must be applied retrospectively. We do not expect the adoption of this ASU to have a material impact on our financial position, results of operations or cash flows.

Note 4. Related Party Transactions

We do not have any employees. We are managed by our general partner, PCEC GP, the executive officers of which are employees of BreitBurn Management. BreitBurn Management operates our assets and performs other administrative services such as accounting, corporate development, finance, land administration, legal and engineering. Prior to June 17, 2008, BreitBurn Management provided services to us and to BBEP, and allocated its expenses between the two entities. On June 17, 2008, BBEP purchased a 95.55% indirect limited liability company interest in BreitBurn Management; consequently, BreitBurn Management became a wholly owned subsidiary of BBEP. We entered into an Amended and Restated Administrative Services Agreement with BreitBurn Management, pursuant to which BreitBurn Management agreed to continue to provide administrative services to us. On August 26, 2008, we entered into a Second Amended and Restated Administrative Services Agreement. Pursuant to the Second Amended and Restated Administrative Services Agreement, the monthly fee payable to BreitBurn Management is to be renegotiated annually in good faith by the parties during the term of the agreement and was set at $500,000, $456,000 and $481,000 for 2009, 2010 and 2011, respectively. The 2012 monthly fee has been set at $571,000 a month. We also reimburse BreitBurn Management monthly for all third party direct costs, long term incentive plan (LTIP) costs and other direct costs relating to the performance of services for us. In the absence of written notice delivered to the other party by either party to the agreement of its intention not to continue under the terms of the agreement, given no later than 180 days before December 31, 2013, and each successive anniversary thereof, the term of the agreement will be extended for one additional calendar year until either or both parties have given notice of their intention to terminate.

At December 31, 2011 and 2010, we had current payables of $3.2 million and $3.4 million, respectively, due to BBEP and its subsidiaries, including BreitBurn Management, related to the Administrative Services Agreement, outstanding liabilities for BreitBurn Management s employee related costs and oil and gas sales made by us on BBEP s behalf for certain properties.

For the years ended December 31, 2011, 2010 and 2009, we sold approximately $13.9 million, $10.3 million and $7.9 million, respectively, of oil and natural gas on BBEP s behalf for BBEP owned properties.

Note 5. Equity Investments

Investment in BEP I

We own a 1% general partner interest in BEP I, which owns an approximate 96% working interest in the East Coyote and Sawtelle oilfields located in the Los Angeles Basin in Southern California. Under BEP I s limited partnership agreement, the general partner of BEP I holds a 35% reversionary interest right applicable to the BEP I properties. As the general partner of BEP I, we will receive an additional 34% interest in BEP I once the limited partner attains payout of its invested capital. This reversionary interest is expected to occur at a defined payout, which is estimated to occur in 2012 based on year-end price and cost projections. BEP I is engaged in the exploitation, development and production of oil and natural gas properties in California. We account for our general partner interest in BEP I using the equity method because of rights held by the limited partner.

On August 26, 2008, as a result of the purchase by PCEH of Provident s interests (see Note 1 for further description of the transaction), the fair value assigned to the investment, including the reversionary interest, was approximately $35.5 million, based on discounted cash flows, quoted market prices and estimates made by management. The difference between the fair value assigned as a result of the purchase by PCEH and our interest in the underlying book basis of BEP I is being amortized over the life of the oil and gas producing fields consistent with the units of production methodology used by BEP I.

For the year ended December 31, 2011, we amortized $0.04 million of our investment, recorded $0.2 million in earnings from BEP I and received approximately $0.2 million in distributions. For the year ended December 31, 2010, we amortized $0.05 million of our investment, recorded $0.2 million in earnings from BEP I and received approximately $0.1 million in distributions. For the year ended December 31, 2009, we amortized $0.2 million of our investment, recorded $0.1 million in earnings from BEP I and received approximately $0.1 million in distributions. Equity earnings and losses, including the amortization of this equity investment, are reported as (Loss) earnings from equity affiliate in the consolidated statements of operations.

At December 31, 2011 and 2010, the net carrying value of the investment was $35.1 million for each of the periods, respectively, and the investment in BEP I approximated the net asset value of the oil and gas fields in BEP I.

Investment in Real Estate Investment Limited Liability Company

We previously had an investment in a real estate limited liability company that we accounted for under the equity method. The real estate investment was written off in 2011 reflecting the dissolution of the real estate limited liability company. Our investment write-off was $1.4 million.

Note 6. Short and Long-Term Debt

On August 26, 2008, in connection with PCEH s acquisition of Provident s indirect interest in us, we, as borrower, and our wholly owned subsidiaries, as guarantors, entered into a four year, $400.0 million second amended and restated revolving credit facility with Wells Fargo Bank, N.A., and a syndicate of banks (the Second Amended and Restated Credit Agreement). We borrowed $90 million on the Second Amended and Restated Credit Agreement and used the funds to pay Provident a portion of the purchase price for the partnership interests purchased by PCEH.

The initial borrowing base of the Second Amended and Restated Credit Agreement was $125.0 million. As of December 31, 2011 and December 31, 2010 our borrowing base was $131.0 million and $115.0 million, respectively. In January 2012, in connection with a scheduled redetermination, our borrowing base was increased to $150.0 million. Under the Second Amended and Restated Credit Agreement, borrowings are allowed to be used for (i) payment of a portion of the acquisition of Provident s indirect partnership interests, (ii) standby letters of credit, (iii) working capital purposes, (iv) general company purposes and (v) certain permitted acquisitions and payments enumerated by the credit facility. Borrowings under the Second Amended and Restated Credit Agreement are secured by first-priority liens on and security interests in substantially all of our and certain of our subsidiaries assets, representing not less than 80% of the total value of our oil and gas properties.

The Second Amended and Restated Credit Agreement contains (i) financial covenants, including leverage, current assets and interest coverage ratios, and (ii) customary covenants, including restrictions on our ability to: (a) incur additional indebtedness; (b) make certain investments, loans or advances; (c) make distributions to unitholders or repurchase units if aggregated letters of credit and outstanding loan amounts exceed 90% of its borrowing base; (d) make dispositions; or (e) enter into a merger or sale of our property or assets, including the sale or transfer of interests in our subsidiaries.

The events that constitute an Event of Default (as defined in the Second Amended and Restated Credit Agreement) include: (i) payment defaults; (ii) misrepresentations; (iii) breaches of covenants; (iv) cross-default and cross-acceleration to certain other indebtedness; (v) adverse judgments against us in excess of a specified amount; (vi) changes in management or control; (vii) loss of permits; (viii) failure to perform under a material agreement; (ix) certain insolvency events; (x) assertion of certain environmental claims; and (xi) occurrence of a material adverse effect. At December 31, 2011 and 2010, we were in compliance with the credit facility s covenants.

On August 26, 2008, in connection with the acquisition of Provident s indirect partnership interests in us, we, as borrower and our wholly owned subsidiaries, as guarantors, also entered into a five year, $60.0 million second lien term loan with Wells Fargo Energy Capital, Metalmark and Greenhill (the Second Lien Credit Agreement). We used the funds to pay Provident for a portion of the purchase price for the partnership interests purchased by PCEH.

As of December 31, 2011 and 2010, we had $74.0 million and $82.0 million, respectively, in debt outstanding under the Second Amended and Restated Credit Agreement that will mature on August 24, 2012, and $30.0 million and $60.0 million, respectively, in debt outstanding under the Second Lien Credit Agreement at each date will mature on February 24, 2013. We plan to replace our Second Amended and Restated Credit Agreement prior to the debt maturity in August 2012. At December 31, 2011, the LIBOR interest rate was 2.03% on the $74.0 million outstanding under the Second Amended and Restated Credit Agreement and the interest rate on the $30.0 million outstanding under the Second Lien Credit Agreement was 8.75%. At December 31, 2010, the LIBOR interest rate was 2.26% on the $82.0 million outstanding under the Second Amended and Restated Credit Agreement and the interest rate on the $60.0 million outstanding under the Second Lien Credit Agreement was 8.75%.

In connection with the acquisition of Provident s indirect partnership interests in us, PCEH issued an unsecured $10 million note payable to Provident maturing in August 2010 that we accounted for as part of our indebtedness. The $10 million note had an annual interest rate of 8% payable quarterly. We paid off the $10 million note payable to Provident during 2010 on behalf of PCEH.

For the year ended December 31, 2011, we recognized interest expense of $6.9 million, net of $0.2 million of capitalized interest. For the year ended December 31, 2010, we recognized interest expense of $8.7 million, net of less than $0.1 million of capitalized interest. For the year ended December 31, 2009, we recognized interest expense of $9.5 million and no capitalized interest.

For the year ended December 31, 2011, 2010 and 2009, we paid $5.8 million, $7.6 million and $8.2 million, respectively, in cash for interest.

Note 7. Asset Retirement Obligation

Our asset retirement obligation is based on our net ownership in wells and facilities and our estimate of the costs to abandon and reclaim those wells and facilities as well as our estimate of the future timing of the costs to be incurred. Payments to settle asset retirement obligations occur over the operating lives of the assets, estimated to be from 12 to 31 years. Estimated cash flows have been discounted to our credit adjusted risk free rate of 7% and adjusted for inflation using a rate of 2%.

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The authoritative guidance for fair value measurements establishes a hierarchy that prioritizes the inputs to valuation techniques into three broad levels based upon how observable those inputs are. The highest priority of Level 1 is given to unadjusted quoted prices in active markets for identical assets or liabilities. Level 2 includes inputs other than quoted prices that are included in Level 1, and can be derived from observable data, including third party data providers. These inputs may also include observable transactions in the market place. Level 3 is given to unobservable inputs. We consider the inputs to our asset retirement obligation valuation to be Level 3, as fair value is determined using discounted cash flow methodologies based on standardized inputs that are not readily observable in public markets.

Changes in the asset retirement obligation for the periods ended:

Thousands of dollars	**At December 31, 2011**	**At December 31, 2010**	**At December 31, 2009**
Carrying amount, beginning of period	$ 16,189	$ 7,205	$ 6,457
Additions	1,059	1,319	
Settlements	(380)	(1,802)	
Revisions[(a)]	4,262	8,946	281
Accretion expense	1,170	521	467
Carrying amount, end of year	$ 22,300	$ 16,189	$ 7,205

(a) Increased cost estimates and revisions to reserve life.

Note 8. Financial Instruments

Fair Value of Financial Instruments

Our risk management programs are intended to reduce exposure to commodity prices and interest rates and to assist with stabilizing cash flows.

Commodity Activities

Due to the historical volatility of crude oil and natural gas prices, we have entered into various derivative instruments to manage exposure to volatility in the market price of crude oil and natural gas to achieve more predictable cash flows. We use swaps, collars and options for managing risk relating to commodity prices. All contracts are settled with cash and do not require the delivery of physical volumes to satisfy settlement. While this strategy may result in us having lower revenues than we would otherwise have if we had not utilized these instruments in times of higher oil and natural gas prices, management believes that the resulting reduced volatility of prices and cash flow is beneficial. While our commodity price risk management program is intended to reduce our exposure to commodity prices and assist with stabilizing cash flow and distributions, to the extent we have hedged a significant portion of our expected production and the cost for goods and services increases, our margins would be adversely affected.

The commodity derivative instruments we utilize are based on index prices that may and often do differ from the actual crude oil and natural gas prices realized in our operations. These variations often result in a lack of adequate correlation to enable these derivative instruments to qualify for cash flow hedge accounting. Accordingly, we do not attempt to account for our commodity derivative instruments as cash flow hedges for financial accounting purposes and instead recognize changes in the fair value immediately in earnings.

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We had the following contracts in place at December 31, 2011:

	Year 2012	Year 2013	Year 2014	Year 2015
Oil Positions:				
Fixed Price Swaps:				
Hedged Volume (Bbls/d)	1,700	1,950	1,658	1,399
Average Price ($/Bbl)	$ 103.14	$ 94.76	$ 91.80	$ 91.63
Collars:				
Hedged Volume (Bbls/d)	650	325	325	325
Average Floor Price ($/Bbl)	$ 110.00	$ 100.00	$ 100.00	$ 100.00
Average Ceiling Price ($/Bbl)	$ 127.10	$ 115.70	$ 116.50	$ 117.25
Floors:				
Hedged Volume (Bbls/d)	750	500		
Average Floor Price ($/Bbl)	$ 70.00	$ 70.00		
Premiums ($/Bbl)	$ 4.63	$ 4.94		
Total:				
Hedged Volume (Bbls/d)	3,100	2,775	1,983	1,724
Average Price ($/Bbl)	$ 96.56	$ 90.91	$ 93.14	$ 93.21
Gas Positions:				
Fixed Price Swaps:				
Hedged Volume (MMBtu/d)	250			
Average Price ($/MMBtu)	$ 7.36			

In the fourth quarter of 2011, in order to improve the effectiveness of our hedge portfolio, we terminated certain crude oil fixed price swaps at NYMEX WTI prices for a total net gain of $16.1 million and entered into new crude oil fixed price swaps for the same volumes and periods at IPE Brent prices. These transactions are reflected in the summary of oil commodity derivatives table above.

Interest Rate Activities

We are subject to interest rate risk associated with loans under our credit facility that bear interest based on floating rates. As of December 31, 2011, our total short-term and long-term debt outstanding was $104.0 million. In order to mitigate our interest rate exposure, we had the following interest rate swaps in place during 2011, to fix a portion of the floating LIBOR-base debt on our credit facility:

Notional amounts in thousands of dollars	**Notional Amount**	**Fixed Rate**
Period Covered		
January 1, 2011 to December 20, 2011	$ 35,000	2.5240%
January 1, 2011 to December 8, 2011	$ 35,000	2.4700%

We do not currently designate our interest rate derivatives as hedges for financial accounting purposes. We did not have any interest rate swaps in place at December 31, 2011.

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Fair Value of Financial Instruments

Accounting standards require disclosures about how and why an entity uses derivative instruments, how derivative instruments and related hedge items are accounted for, and how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. The required disclosures are detailed below.

Fair value of derivative instruments not designated as hedging instruments:

Balance Sheet location, thousands of dollars	**Oil Commodity Derivatives**	**Natural Gas Commodity Derivatives**	**Interest Rate Derivatives**	**Commodity derivatives netting[(a)]**	**Total Financial Instruments**
December 31, 2011					
Assets					
Short-term assets	$ 1,482	$	$	$	$ 1,482
Long-term assets	409				409
Total assets	1,891				1,891
Liabilities					
Short-term liabilities	(520)	(346)			(866)
Long-term liabilities	(3,059)				(3,059)
Total liabilities	(3,579)	(346)			(3,925)
Net liabilities	$ (1,688)	$ (346)	$	$	$ (2,034)
December 31, 2010					
Assets					
Short-term assets	$ 9,380	$	$	$	$ 9,380
Long-term assets	11,456			(221)	11,235
Total assets	20,836			(221)	20,615
Liabilities					
Short-term liabilities	(1,477)	(261)	(1,375)		(3,113)
Long-term liabilities	(1,275)	(221)		221	(1,275)
Total liabilities	(2,752)	(482)	(1,375)	221	(4,388)
Net assets (liabilities)	$ 18,084	$ (482)	$ (1,375)	$	$ 16,227

(a) Represents counterparty netting under derivative netting agreements these contracts are reflected net on the balance sheet.

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Gain and loss on derivative instruments not designated as hedging instruments:

Thousands of dollars	Oil Commodity Derivatives	Natural Gas Commodity Derivatives	Interest Rate Derivatives	Total Financial Instruments
Year Ended December 31, 2011				
Realized gain (loss) on derivative instruments	$ 23,793	$ (305)	$ (1,469)	$ 22,019
Unrealized gain on derivative instruments	(20,456)	135	1,375	(18,946)
Total gain (loss) on derivative instruments	$ 3,337	$ (170)	$ (94)	$ 3,073
Year Ended December 31, 2010				
Realized gain (loss) on derivative instruments	$ 15,722	$ (296)	$ (1,583)	$ 13,843
Unrealized gain (loss) on derivative instruments	(30,107)	(154)	273	(29,988)
Total loss on derivative instruments	$ (14,385)	$ (450)	$ (1,310)	$ (16,145)
Year Ended December 31, 2009				
Realized gain (loss) on derivative instruments	$ 26,303	$ (459)	$ (1,539)	$ 24,305
Unrealized gain (loss) on derivative instruments	(86,038)	(350)	381	(86,007)
Total loss on derivative instruments	$ (59,735)	$ (809)	$ (1,158)	$ (61,702)

Gains and losses on commodity derivative instruments are included in gain (loss) on commodity derivative instruments, net on the consolidated statements of operations. Gains and losses on interest rate swaps are included in loss on interest rate derivative instruments on the consolidated statements of operations. While our commodity and interest rate price risk management program is intended to reduce our exposure to commodity prices and assist with stabilizing cash flow, to the extent that it has hedged a significant portion of our expected production and the cost for goods and services increases, our margins would be adversely affected.

Authoritative guidance defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. It also establishes a fair value hierarchy that prioritizes the inputs to valuation techniques into three broad levels based upon how observable those inputs are. We use valuation techniques that maximize the use of observable inputs and obtain the majority of our inputs from published objective sources or third party market participants. We incorporate the impact of nonperformance risk, including credit risk, into our fair value measurements. The fair value hierarchy gives the highest priority of level 1 to unadjusted quoted prices in active markets for identical assets or liabilities and the lowest priority of level 3 to unobservable inputs. We categorize our fair value financial instruments based upon the objectivity of the inputs and how observable those inputs are. The three levels of inputs are described further as follows:

Level 1 Unadjusted quoted prices in active markets for identical assets or liabilities as of the reporting date. Level 2 Inputs other than quoted prices that are included in Level 1. Level 2 includes financial instruments that are actively traded but are valued using models or other valuation methodologies. We consider the over the counter (OTC) commodity and interest rate swaps in our portfolio to be Level 2. Level 3 Inputs that are not directly observable for the asset or liability and are significant to the fair value of the asset or liability. Level 3 includes financial instruments that are not actively traded and have little or no observable data for input into industry standard models. Certain OTC derivatives that trade in less liquid markets or contain limited observable model inputs are currently included in Level 3. As of December 31, 2011 and December 31, 2010, Level 3 assets and liabilities consisted entirely of OTC commodity put and call options.

Financial assets and liabilities that are categorized in Level 3 may later be reclassified to the Level 2 category at the point we are able to obtain sufficient binding market data or the interpretation of Level 2 criteria is modified in practice to include non-binding market corroborated data. We had no transfers in or out of Levels 1, 2 or 3 during years ended December 31, 2011, 2010 and 2009. Our policy is to recognize transfers in and out of Level 3 as of the end of the period.

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As mentioned in Note 4, BreitBurn Management provides us with general management services, including risk management activities. BreitBurn Management s Treasury/Risk Management group calculates the fair value of our commodity and interest rate swaps and options. We compare these fair value amounts to the fair value amounts that we receive from the counterparties on a monthly basis. Any differences are resolved and any required changes are recorded prior to the issuance of our financial statements.

The model utilized to calculate the fair value of our commodity derivative instruments is a standard option pricing model. Inputs to the option pricing models include fixed monthly commodity strike prices and volumes from each specific contract, commodity prices from commodity forward price curves, volatility and interest rate factors and time to expiry. Model inputs are obtained from our counterparties and third party data providers and are verified to published data where available (e.g., NYMEX). Additional inputs to our Level 3 derivatives include option volatility, forward commodity prices and risk-free interest rates for present value discounting. The standard swap contract valuation method is used to value our interest rate derivatives, and inputs include LIBOR forward interest rates, one-month LIBOR rates and risk-free interest rates for present value discounting. Determination of fair values incorporates various factors including, but not limited to, the credit standing of the counterparties, the impact of guarantees as well as our own abilities to perform on our liabilities.

Our assessment of the significance of an input to its fair value measurement requires judgment and can affect the valuation of the assets and liabilities as well as the category within which they are classified. Financial assets and liabilities carried at fair value on a recurring basis are presented in the following table:

	As of December 31, 2011			
Thousands of dollars	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets (liabilities):				
Commodity derivatives (swaps, put and call options)	$	$ (7,765)	$ 5,731	$ (2,034)
Total	$	$ (7,765)	$ 5,731	$ (2,034)

	As of December 31, 2010			
Thousands of dollars	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets (liabilities):				
Commodity derivatives (swaps, put and call options)	$	$ 6,147	$ 11,455	$ 17,602
Other derivatives (interest rate swaps)		(1,375)		(1,375)
Total	$	$ 4,772	$ 11,455	$ 16,227

The following table sets forth a roll-forward of our derivative instruments classified as Level 3:

	Year Ended December 31,		
Thousands of dollars	**2011**	**2010**	**2009**
Assets (liabilities):			
Balance, beginning of period	$ 11,455	$ 23,910	$ 55,523
Realized gain	2,938	7,347	13,922
Unrealized loss	(9,347)	(19,802)	(45,267)
Purchases and issuances	685		
Settlements			(268)
Balance, end of period	$ 5,731	$ 11,455	$ 23,910

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Credit and Counterparty Risk

Financial instruments which potentially subject us to concentrations of credit risk consist principally of derivatives and accounts receivable. Our derivatives expose us to credit risk from counterparties. As of December 31, 2011, our derivative counterparties were Wells Fargo Bank National Association, Bank of Montreal, Union Bank, N.A., Royal Bank of Scotland plc and Bank of Nova Scotia. Our counterparties are all lenders under our Amended and Restated Credit Agreement. Our credit agreement is secured by our crude oil, natural gas and NGL reserves, so we are not required to post any collateral, and we conversely do not receive collateral from our counterparties. On all transactions where we are exposed to counterparty risk, we analyze the counterparty s financial condition prior to entering into an agreement, establish limits, and monitor the appropriateness of these limits on an ongoing basis. We periodically obtain credit default swap information on our counterparties. As of December 31, 2011, each of these financial institutions carried an investment grade credit rating. Although we currently do not believe we have a specific counterparty risk with any party, our loss could be substantial if any of these parties were to fail to perform in accordance with the terms of the contract. As of December 31, 2011, our derivative asset balances were with Wells Fargo Bank, N.A. and Bank of Montreal, who accounted for 78% and 22% of our derivative asset balances, respectively. As of December 31, 2011, our derivative liability balances were with Wells Fargo Bank, N.A., Royal Bank of Scotland plc, Bank of Nova Scotia, Union Bank, N.A., and Bank of Montreal who accounted for approximately 32%, 31%, 28%, 7% and 2% of our derivative liability balances, respectively.

Note 9. Property taxes

In 2010, we received a supplemental property tax billing for the period from July 1, 2009 to June 30, 2010 for one of our oil and gas properties located in Santa Barbara County. This supplemental billing indicates that it is related to oil and gas property re-assessments due to the ownership change that occurred on August 26, 2008 when PCEH was formed. We previously received and paid a supplemental property tax billing for the period from August 26, 2008 to June 30, 2009 related to the ownership change that occurred on August 26, 2008 for the same oil and gas properties located in Santa Barbara County. We believe that the supplemental bill received in 2010 is erroneous. In 2010, we filed an appeal for this reassessment. In April 2011, we began to pay the amount under protest in five equal annual installments as allowed by California statutes, because we are legally required to pay this amount. We recorded the full amount of the reassessment liability of $1.5 million as of December 31, 2010. Of this amount, we paid $0.3 million in April 2011. As of December 31, 2011, we have recorded $0.3 million in other current liabilities representing the current portion of the property tax liability for the amount we intend to pay in April 2012. The remaining $0.9 million was recorded in other long-term liabilities reflecting the amount we intend to pay over the next four years.

Also in 2010, we received the annual tax bill for oil and gas properties located in Santa Barbara County for the July 1, 2010 to June 30, 2011 fiscal year. Upon examination of the tax bill, it was discovered that the assessed value for the oil and gas properties contained a material calculation error. We contacted the Santa Barbara County Tax Assessor s office about the error and were advised to pay the invoice by its installment due dates and file an appeal with the Santa Barbara County Tax Assessor. We immediately filed an appeal with the Santa Barbara County Tax Assessor s office to have the error in assessed value corrected. In December 2010, we paid $1.5 million representing the first installment of the July 1, 2010 to December 31, 2010 portion of the annual tax liability under protest. We are currently in consultation with an outside property tax attorney to determine the range of possible remedies, including litigation proceedings, that may be available to expedite the property tax appeal process.

Note 10. Stock and Other Valuation-Based Compensation Plans

We have no employees and are managed by PCEC GP, the executive officers of which are employees of BreitBurn Management. We entered into an administrative services agreement with BreitBurn Management pursuant to which it operates our assets and performs other administrative services. As such, we account for our current and future incentive compensation plans following guidance for non-employee awards.

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PCEH Long-Term Incentive Plan

The PCEH Long-Term Incentive Plan (the Plan) was adopted by PCEH beginning in 2009. The Plan is intended to promote our interest by providing incentive compensation to Employees of BreitBurn Management as defined in the Plan. Under the Plan, 94,714, 83,590 and 91,847 deferred non-voting Class A PCEH units (Deferred Units) were awarded to Employees during 2011, 2010 and 2009, respectively. The Deferred Units vest in two ways: 60% of the Deferred Units are time-based units (Time-Based Units) and vest one fifth annually subject to continued service by the recipient through each vesting period; the remaining 40% of the Deferred Units are performance-based units (Performance-Based Units) that vest in full upon the consummation of (i) a sale by either the sale, lease, transfer, conveyance or other disposition, in one or a series of related transactions, of all or substantially all of the assets of the PCEH and its subsidiaries, taken as a whole, or of a majority of the outstanding equity interests, including by merger or consolidation, to a third-party, or any merger, consolidation or other business combination, as a result of which the Class A Unitholders immediately prior to such transaction or transactions do not own a majority of the outstanding equity of the surviving entity or (ii) an Initial Public Offering for a substantial amount of PCEH s equity securities or the equity securities of a subsidiary (realization event). Deferred Units that do not vest for any reason are forfeited upon a grantee s termination of employment. Each Time-Based Deferred Unit will be settled by the delivery of one Class A unit on December 31, 2015, or earlier upon the occurrence of a realization event, death, disability or termination without cause subject to pro-rata vesting. Performance-Based Units will be settled by the delivery of one Class A unit upon the occurrence of a realization event.

The Time-Based Units are equity-classified awards and were initially valued at a fair market price of $10 per unit in 2010 and 2009. In 2011, all Time-Based Units were revalued to a fair market price of $12.80 per unit primarily as a result of PCEC s ongoing drilling program at Orcutt field. As the Company s Class A Units are not publicly-traded on the exchanges, the fair value of the awards represent a composite average of values as determined by various valuation models, including an income based approach utilizing discounted cash flows, reviewing average peer group financial performance multiples to market value, and examining publicly available proved reserves and production data of peer companies as compared to PCEC. We also recognize the compensation expense on a graded-vesting method over the requisite service period for each separately vesting tranche of the awards as if they were, in substance, multiple awards. For Performance-Based Units, we cannot predict with certainty when or if a realization event will occur. Accordingly, compensation expense for these awards will be recognized upon the occurrence of a realization event.

Deferred Unit awards were granted to BreitBurn Management employees in 2011, 2010 and 2009, as shown in the table below:

	Year Ended December 31,					
	2011		2010		2009	
	Time-Based Units	Performance Based Units	Time-Based Units	Performance Based Units	Time-Based Units	Performance Based Units
Outstanding, beginning of period	53,914	51,441	43,768	36,470		
Granted	56,829	37,885	50,155	33,435	55,105	36,742
Cancelled	(4,009)	(3,941)	(24,567)	(18,464)	(409)	(272)
Vested	(33,149)		(15,442)		(10,928)	
Outstanding, end of period	73,585	85,385	53,914	51,441	43,768	36,470

In 2011, we recognized compensation expense of $0.7 million for Time-Based Units. The remaining unvested value at December 31, 2011 was $0.5 million, which will be recognized over the next four years. In 2010, we recognized compensation expense of $0.2 million for Time-Based Units. In 2009, we recognized compensation expense of $0.2 million for Time-Based Units.

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Note 11. Commitments and Contingencies

We are involved in various lawsuits, claims and inquiries, most of which are routine to the nature of our business. In our opinion, the resolution of these matters will not have a material effect on our financial position, results of operations or liquidity.

Our contractual obligations at December 31, 2011 are summarized as follows:

Thousands of dollars	Payments Due by Year						
	2012	2013	2014	2015	2016	after 2016	Total
Revolving credit facility	$ 74,000	$	$	$	$	$	$ 74,000
Credit facility commitment fees	77						77
Second lien credit agreement		30,000					30,000
Estimated interest payments	4,160	2,803					6,963
Vehicle, and equipment leases	135	96	58	15	4		308
Asset retirement obligation						22,300	22,300
Total	$ 78,372	$ 32,899	$ 58	$ 15	$ 4	$ 22,300	$ 133,648

Under the Second Amended and Restated Administrative Services Agreement, we pay BreitBurn Management an indirect fee that covers a pro-rata amount of the expenditures for office space, and vehicle and office equipment leases (see Note 4 Related Party Transactions). We are not a party to those leases. We are a party to the vehicle leases reflected in the table above. Our debt and asset retirement obligations are discussed in Notes 6 and 7, respectively.

Note 12. Partners Equity

We paid on behalf of PCEH certain administrative costs. The accumulated amounts paid on behalf of PCEH are reflected as a reduction of Partners Equity. At December 31, 2009, 2010 and 2011, we had $0.8 million, $1.5 million, and $2.2 million, respectively, of accumulated PCEH amounts.

Note 13. Subsequent Events

On January 17, 2012, we entered into crude oil fixed price swap contracts for 500 Bbl/d for the period January 1, 2014 to December 31, 2014 at $99.90 per Bbl and 800 Bbl/d for the period January 1, 2015 to December 31, 2015 at $96.45 per Bbl.

Note 14. Subsequent Events (Unaudited)

On March 6, 2012, we terminated a crude oil option contract for 200 Bbl/d for the period from January 1, 2012 to December 31, 2012 at NYMEX WTI $70.00 per Bbl at a cost of $0.2 million and also terminated crude oil fixed price swaps at a cost of $12.4 million as follows:

Period	Average IPE Brent $/Bbl	Volume Bbl/d
April 1, 2012 to December 31, 2012	$ 102.68	1,250
January 1, 2013 to December 31, 2013	99.20	1,125
January 1, 2014 to March 31, 2014	95.55	1,050

Concurrently with the terminations, we entered into a new crude oil fixed price swap for 2,000 Bbl/day for the period April 1, 2012 to March 31, 2014 at IPE Brent $115.00 per Bbl at a cost of $3.0 million.

On March 12, 2012, PCEC paid $9.2 million to the individual partners of PCEH, the sole member of PCEC s general partner. The payment is intended to enable PCEH s individual partners to pay their U.S. federal, state and local tax liabilities relating to their taxable income in the partnership.

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In April 2012 we reached an agreement in principle with BreitBurn Management to amend and restate the Second Amended and Restated Services Agreement, which we expect to formalize by executing the Third Amended and Restated Administrative Services Agreement in connection with the closing of this offering. Pursuant to our agreement, we will pay a fixed, monthly fee of $700,000 in exchange for the administrative services provided by BBEP through the end of the term, which will be extended through August 31, 2014, and a one-time fee of $250,000. In connection with the amendment to the Second Amended and Restated Services Agreement, BBEP s right of first offer with respect to the sale of our assets under the Omnibus Agreement will terminate.

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Supplemental Information

Oil and Natural Gas Activities (Unaudited)

We calculate total estimated proved reserves and disclose our oil and natural gas activities in accordance with SEC guidelines. The definition of proved reserves incorporates a definition of reasonable certainty using the PRMS (Petroleum Resource Management System) standard of high degree of confidence for deterministic method estimates, or a 90% recovery probability for probabilistic methods used in estimating proved reserves. While SEC guidelines permit a company to establish undeveloped reserves as proved with appropriate degrees of reasonable certainty established absent actual production tests and without artificially limiting such reserves to spacing units adjacent to a producing well, we have elected not to add such undeveloped reserves as proved. For reserve reporting purposes we use unweighted average first-day-of-the-month pricing for the prior 12 calendar months. Costs associated with reserves are measured on the last day of the fiscal year.

Costs incurred

Our oil and natural gas activities are conducted in the United States. The following table summarizes our costs incurred for the past three years:

	Year Ended December 31,		
Thousands of dollars	**2011**	**2010**	**2009**
Development costs	$ 29,901	$ 44,000	$ 15,852
Asset retirement costs development	5,321	10,265	281
Total costs incurred	$ 35,222	$ 54,265	$ 16,133

Capitalized costs

The following table presents the aggregate capitalized costs subject to depreciation, depletion and amortization relating to oil and gas activities, and the aggregate related accumulated allowance:

	At December 31,	
Thousands of dollars	**2011**	**2010**
Proved properties and related producing assets	$ 421,207	$ 385,939
Accumulated depreciation, depletion and amortization	(93,846)	(74,210)
Net capitalized costs	$ 327,361	$ 311,729

The average DD&A rate per equivalent unit of production for the year ended December 31, 2011, excluding non-oil and gas related DD&A, was $17.12 per Boe. The average DD&A rate per equivalent unit of production for the year ended December 31, 2010, excluding non-oil and gas related DD&A, was $23.60 per Boe.

Results of operations for oil and gas producing activities

The results of operations from oil and gas producing activities below exclude non-oil and gas revenues and expenses, general and administrative expenses, interest expenses and interest income.

	Year Ended December 31,		
Thousands of dollars	**2011**	**2010**	**2009**
Oil, natural gas and NGL sales	$ 106,809	$ 76,898	$ 66,842
Gain (loss) on commodity derivative instruments	3,167	(14,835)	(60,544)

Operating costs	(39,337)	(35,527)	(38,651)
Dry hole costs		(2,752)	
Depreciation, depletion, and amortization	(20,806)	(26,639)	(42,225)
Results of operations from producing activities	$ 49,833	$ (2,855)	$ (74,578)

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Supplemental reserve information

The following information summarizes our estimated proved reserves of oil (including condensate and natural gas liquids) and natural gas and the present values thereof for the years ended December 31, 2011, 2010 and 2009. The following reserve information is based upon reports by Netherland, Sewell & Associates, Inc. (NSAI), an independent petroleum engineering firm. The estimates are prepared in accordance with SEC regulations. We utilize a large, widely known, highly regarded, and reputable engineering consulting firm. Not only the firm, but the technical persons that sign and seal the reports are licensed and certify that they meet all professional requirements. Licensing requirements formally require mandatory continuing education and professional qualifications. They are independent petroleum engineers, geologists, geophysicists and petrophysicists.

Our reserve estimation process involves petroleum engineers and geoscientists. As part of this process, all reserves volumes are estimated using a forecast of production rates, current operating costs and projected capital expenditures. Reserves are based on the unweighted average first-day-of-the-month prices for each of the three fiscal years. Price differentials are than applied to adjust to expected realized field price. Specifics of each operating agreement are then used to estimate the net reserves. Production rate forecasts are derived by a number of methods, including decline curve analyses, volumetrics, material balance or computer simulation of the reservoir performance. Operating costs and capital costs are forecast using current costs combined with expectations of future costs for specific reservoirs. In many cases, activity-based cost models for a reservoir are utilized to project operating costs as production rates and the number of wells for production and injection vary.

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. J. Carter Henson, Jr. has been practicing consulting petroleum engineering at NSAI since 1989. Carter is a Registered Professional Engineer in the State of Texas (License No. 73964) and has over 30 years of practical experience in petroleum engineering, with over 22 years experience in the estimation and evaluation of reserves. He graduated from Rice University in 1981 with a Bachelor of Science Degree in Mechanical Engineering. Mike Norton has been practicing consulting petroleum geology at NSAI since 1989. Mike is a Certified Petroleum Geologist in the State of Texas (License No. 441) and has over 33 years of practical experience in petroleum geosciences, with over 28 years 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 geosciences evaluations as well as applying SEC and other industry reserves definitions and guidelines.

The technical person primarily responsible for overseeing preparation of the reserves estimates and the third party reserve reports is Mark Pease, the Executive Vice President and Chief Operating Officer of BreitBurn Management, the company that manages PCEC GP, the general partner of PCEC. He received a Bachelor of Science in Petroleum Engineering from the Colorado School of Mines in 1979. Prior to joining BreitBurn Management, he was Senior Vice President, E&P Technology & Services for Anadarko Petroleum Corporation. He has over 30 years of experience working in various capacities in the energy industry, including acquisition analysis, reserve estimation, reservoir engineering and operations engineering. He consults regularly with Netherland Sewell during the reserve estimation process to review properties, assumptions and relevant data. Additionally, PCEC s senior management have reviewed and approved all Netherland Sewell summary reserve reports.

Management believes the reserve estimates presented herein, in accordance with generally accepted engineering and evaluation principles consistently applied, are reasonable. However, there are numerous uncertainties inherent in estimating quantities and values of the estimated proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control.

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Reserve engineering is a subjective process of estimating the recovery from underground accumulations of oil and gas that cannot be measured in an exact manner and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Because all reserve estimates are to some degree speculative, the quantities of oil and gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil and gas sales prices may all differ from those assumed in these estimates. In addition, different reserve engineers may make different estimates of reserve quantities and cash flows based upon the same available data. Therefore, the standardized measure of discounted net future cash flows shown below represents estimates only and should not be construed as the current market value of the estimated oil and gas reserves attributable to our properties. In this regard, the information set forth in the following tables includes revisions of reserve estimates attributable to proved properties included in the preceding year s estimates. Such revisions reflect additional information from subsequent exploitation and development activities, production history of the properties involved and any adjustments in the projected economic life of such properties resulting from changes in product prices. Decreases in the prices of oil and natural gas and increases in operating expenses have had, and could have in the future, an adverse effect on the carrying value of our proved reserves and revenues, profitability and cash flow.

The following table sets forth certain data pertaining to our estimated proved and proved developed reserves for the years ended December 31, 2011, 2010 and 2009. In 2011, 2010 and 2009, the unweighted average first-day-of-the-month market prices used to determine oil reserves were $95.97 per Bbl of oil, $79.40 per Bbl of oil and $61.18 per Bbl of oil, respectively, and the market prices used to determine natural gas reserves were $4.12 per MMBtu of gas, $4.38 per MMBtu of gas and $3.87 per MMBtu of gas, respectively.

	Year Ended December 31,								
	2011			2010			2009		
	Total (MBoe)	Oil (MBbl)	Gas (MMcf)	Total (MBoe)	Oil (MBbl)	Gas (MMcf)	Total (MBoe)	Oil (MBbl)	Gas (MMcf)
Proved Reserves									
Beginning balance	19,309	18,508	4,808	12,842	12,334	3,049	6,882	6,851	187
Revision of previous estimates	4,408	4,357	307	7,596	7,260	2,018	7,251	6,723	3,167
Extensions, discoveries and other additions	11,626	11,626							
Production	(1,215)	(1,171)	(264)	(1,129)	(1,086)	(259)	(1,291)	(1,240)	(305)
Ending balance	34,128	33,320	4,851	19,309	18,508	4,808	12,842	12,334	3,049
Proved Developed Reserves[a]									
Beginning balance	17,462	16,982	2,879	11,566	11,320	1,475	6,442	6,411	187
Ending balance	21,124	20,548	3,458	17,462	16,982	2,879	11,566	11,320	1,475
Proved Undeveloped Reserves[a] [b]									
Beginning balance	1,847	1,526	1,929	1,276	1,014	1,574	440	440	
Ending balance	13,004	12,772	1,393	1,847	1,526	1,929	1,276	1,014	1,574

(a) During the years ended December 31, 2011 and 2010, we incurred $2.2 million and $11.8 million, respectively, in capital expenditures and drilled and completed two wells and three wells, respectively, related to the conversion of proved undeveloped to proved developed reserves. During the years ended December 31, 2011 and 2010, we converted 20 MBbl of oil and 202 MBbl of oil, respectively, and zero MMcf of natural gas and 371 MMcf of natural gas, respectively, from proved undeveloped to proved developed reserves.

(b) As of December 31, 2011 and 2010, we had no material proved undeveloped reserves that had remained undeveloped for more than five years.

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Revisions of Previous Estimates

In 2011, we had positive revisions of 4.4 MMBoe, primarily due to an increase in oil prices. Unweighted average first-day-of-the-month crude oil prices used to determine our total estimated proved reserves as of December 31, 2011 were $95.97 per Bbl of oil compared to $79.40 per Bbl for 2010.

In 2010, we had positive revisions of 7.6 MMBoe, primarily due to an increase in oil prices and natural gas prices. Unweighted average first-day-of-the-month crude oil prices used to determine our total estimated proved reserves as of December 31, 2010 were $79.40 per Bbl of oil and $4.38 per MMBtu of gas compared to $61.18 per Bbl and $3.87 per MMBtu of gas for 2009.

Revision of Proved Undeveloped Reserves

The 11,157 MBoe increase in proved undeveloped reserves during the year ended December 31, 2011, was driven by technical and economic success from positive results from test wells drilled in connection with an expansion at PCEC s Orcutt Diatomite properties. The 571 MBoe increase in proved undeveloped reserves during the year ended December 31, 2010, consists of 409 MBoe positive revisions as a result of higher oil and natural gas prices from production from PCEC s West Pico property and 162 MBoe due to positive results from wells drilled to the SX formation at PCEC s conventional Orcutt properties.

Standardized measure of discounted future net cash flows

The Standardized Measure of discounted future net cash flows relating to our estimated proved crude oil and natural gas reserves as of December 31, 2011, 2010 and 2009 is presented below:

	Year Ended December 31,		
Thousands of dollars	**2011**	**2010**	**2009**
Future cash inflows	$ 3,198,157	$ 1,326,482	$ 668,585
Future development costs	(251,692)	(53,424)	(48,402)
Future production expense	(1,430,646)	(766,789)	(462,174)
Future net cash flows	1,515,819	506,269	158,009
Discounted at 10% per year	(854,293)	(229,808)	(68,945)
Standardized measure of discounted future net cash flows	$ 661,526	$ 276,461	$ 89,064

The standardized measure of discounted future net cash flows discounted at ten percent from production of proved reserves was developed as follows:

1. An estimate was made of the quantity of proved reserves and the future periods in which they are expected to be produced based on year-end economic conditions.

2. In accordance with SEC guidelines, the reserve engineers estimates of future net revenues from our estimated proved properties and the present value thereof are made using unweighted average first-day-of-the-month oil and gas sales prices and are held constant throughout the life of the properties, except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. We have entered into various derivative instruments to fix or limit the prices relating to a portion of our oil and gas production. Derivative instruments in effect at December 31, 2011 are discussed in Note 8. Such derivative instruments are not reflected in the reserve reports. Representative unweighted average first-day-of-the-month market prices for the reserve reports for the year ended December 31, 2011 were $95.97 per barrel of oil and $4.12 per MMBtu of gas. Representative unweighted average first-day-of-the-month market prices for the reserve reports for the year ended December 31, 2010 were $79.40 per barrel of oil and $4.38 per MMBtu of gas. Representative unweighted average first-day-of-the-month market prices for the reserve reports for the year ended December 31, 2009 were $61.18 per barrel of oil and $3.87 per MMBtu of gas.

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3. The future gross revenue streams were reduced by estimated future operating costs (including production and ad valorem taxes) and future development and abandonment costs, all of which were based on current costs. Future net cash flows assume no future income tax expense as we are essentially a non-taxable entity except for two tax paying corporations whose future income tax liabilities on a discounted basis are insignificant.

The principal sources of changes in the Standardized Measure of the future net cash flows for the years ended December 31, 2011, 2010 and 2009 are presented below:

	Year Ended December 31,		
Thousands of dollars	**2011**	**2010**	**2009**
Beginning balance	**$ 276,461**	**$ 89,064**	**$ 35,778**
Sales, net of production expense	(67,742)	(41,371)	(28,191)
Net change in sales and transfer prices, net of production expense	216,937	147,721	59,699
Previously estimated development costs incurred during year	11,337	12,556	11,078
Changes in estimated future development costs	(26,361)	(47,846)	(24,612)
Extensions, discoveries and improved recovery, net of costs	154,890		
Revision of quantity estimates and timing of estimated production	68,358	107,430	31,734
Accretion of discount	27,646	8,907	3,578
Ending balance	**$ 661,526**	**$ 276,461**	**$ 89,064**

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PACIFIC COAST ENERGY COMPANY LP

Unaudited Pro Forma Financial Statements

Introduction

The following unaudited pro forma financial statements have been prepared to illustrate: (i) the conveyance of the net profits and royalty interest (the Conveyed Interests) in certain oil and natural gas producing properties located in California (the Underlying Properties) by Pacific Coast Energy Company LP (PCEC) to Pacific Coast Oil Trust (the Trust); (ii) the sale of trust units to the public; (iii) the repayment of outstanding borrowings under PCEC s senior secured credit agreement and second lien credit agreement and (iv) the distribution of a portion of proceeds to the equity owners of PCEC. The unaudited pro forma balance sheet is presented as of December 31, 2011, and gives effect to the (a) sale of trust units at $ per unit, (b) Conveyed Interests conveyance, (c) repayment of outstanding borrowings under PCEC s senior secured credit agreement and second lien credit agreement and (d) distribution to the equity owners of PCEC of a portion of the net proceeds from the sale of the trust units as if they occurred on December 31, 2011. The unaudited pro forma statement of operations presents the historical statement of operations of PCEC for the year ended December 31, 2011 giving effect to the Conveyed Interests conveyance and the repayment of PCEC s borrowings under its senior secured credit agreement and second lien credit agreement as if they occurred on January 1, 2011, reflecting only pro forma adjustments expected to have a continuing impact on the results.

These unaudited pro forma financial statements are for informational purposes only. They do not purport to present the results that would have actually occurred had the Conveyed Interest conveyance, the repayment of borrowings under PCEC s senior secured credit agreement and second lien credit agreement, and the distribution to the equity owners of PCEC been completed on the assumed dates or for the periods presented. Moreover, they do not purport to project PCEC s financial position or results of operations for any future date or period.

To produce the pro forma financial statements, PCEC s management made certain estimates. These estimates are based on the most recently available information. To the extent there are significant changes in these amounts, the assumptions and estimates herein could change significantly. The unaudited pro forma financial statements should be read in conjunction with the accompanying notes to such unaudited pro forma financial statements, Information About Pacific Coast Energy Company LP Management s Discussion and Analysis of Financial Condition and Results of Operations of PCEC and the audited historical financial statements of PCEC included in this prospectus and elsewhere in the registration statement.

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Pacific Coast Energy Company LP and Subsidiaries

Unaudited Pro Forma Balance Sheet

In thousands	Historical	December 31, 2011 Adjustments	Pro Forma
ASSETS			
Current assets:			
Cash	$ 1,380	$ 1,620[(a)]	$ 3,000
Accounts receivable, net	13,428		13,428
Derivative instruments	1,482		1,482
Prepaid expenses	115		115
Total current assets	16,405	1,620	18,025
Equity investment	35,067		35,067
Property, plant and equipment			
Oil and gas properties	421,207	(144,883)[(b)]	276,324
Non-oil and gas assets	9,149		9,149
	430,356	(144,883)	285,473
Accumulated depletion and depreciation	(94,241)	34,085[(b)]	(60,156)
Net property, plant and equipment	336,115	(110,798)	225,317
Other long-term assets			
Derivative instruments	409		409
Other long-term assets	4,682		4,682
Total assets	$ 392,678	$ (109,178)	$ 283,500
LIABILITIES AND EQUITY			
Current liabilities:			
Accounts payable	$ 7,628	$	$ 7,628
Derivative instruments	866		866
Short-term debt	74,000	(24,000)[(a)]	50,000
Related party payables	3,159		3,159
Revenue and royalties payable	3,970		3,970
Other current liabilities	744		744
Total current liabilities	90,367	(24,000)	66,367
Long-term debt	30,000	(30,000)[(a)]	
Asset retirement obligation	22,300		22,300
Derivative instruments	3,059		3,059
Other long-term liabilities	899		899
Total liabilities	146,625	(54,000)	92,625
Equity:			
Partners equity	246,053	210,677[(c)]	190,875
		(265,855)[(a)]	
Total equity	246,053	(55,178)	190,875
Total liabilities and equity	$ 392,678	$ (109,178)	$ 283,500

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

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Pacific Coast Energy Company LP and Subsidiaries

Unaudited Pro Forma Statement of Operations

	Year Ended December 31, 2011		
In thousands	**Historical**	**Adjustments**	**Pro Forma**
Revenues and other income items:			
Oil, natural gas and natural gas liquid sales	$ 106,809	$ (13,778)[(d)]	$ 93,031
Loss on commodity derivative instruments, net	3,167		3,167
Loss from equity affiliate	(1,182)		(1,182)
Other revenue, net	1,988		1,988
Total revenues and other income items	110,782	(13,778)	97,004
Operating costs and expenses:			
Operating costs	39,337		39,337
Depletion, depreciation and amortization	20,905	(7,557)[(e)]	13,348
Dry hole costs			
General and administrative expenses	8,757		8,757
Total operating costs and expenses	68,999	(7,557)	61,442
Operating income	41,783	(6,221)	35,562
Interest and other financing costs, net	6,947	(3,141)[(f)]	3,806
Loss on interest rate derivative instruments	94		94
Other expense, net	115		115
Total other expenses, net	7,156	(3,141)	4,015
Net income	$ 34,627	$ (3,080)	$ 31,547

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

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Notes to Unaudited Pro Forma Financial Statements

Note 1. Basis of Presentation

PCEC will convey to the Trust the net profits interests (the Net Profits Interests) and royalty interest (together with the Net Profits Interest, the Conveyed Interests) in the Orcutt properties located onshore in the Santa Maria Basin and the East Coyote, Sawtelle and West Pico properties located onshore in the Los Angeles Basin held by PCEC (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 on the Underlying Properties as of December 31, 2011 (the Developed Properties) and either a 7.5% royalty interest from the sale of oil and natural gas production from the other development potential on the Underlying Properties (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.

In exchange for the conveyance of the Conveyed Interests, PCEC will receive trust units. The unaudited pro forma balance sheet assumes PCEC will sell of the trust units at $ per unit and will incur estimated direct transaction costs of approximately $ million (comprised of underwriter, legal, accounting and other fees).

PCEC will recognize a gain on the sale of the units representing the difference between the net proceeds of the offering and the historical costs of the Conveyed Interests conveyed. The gain on sale of units has been excluded from the unaudited pro forma statement of operations as the item is non-recurring.

The net proceeds of the offering will be used to repay borrowings outstanding under PCEC s senior secured credit agreement and second lien credit agreement, to make a distribution to the equity owners of PCEC and for general corporate purposes.

Note 2. Pro Forma Adjustments

Pro forma adjustments are necessary to reflect the Conveyed Interests conveyance to the Trust and related issuance of the trust units, the sale of trust units to the public, repayment of borrowings outstanding under PCEC s senior secured credit agreement and second lien credit agreement and a distribution to the equity owners of PCEC. The pro forma adjustments included in the unaudited pro forma financial statements are as follows:

The pro forma adjustments included in the unaudited pro forma balance sheet are as follows (in thousands):

(a)	Gross cash proceeds from sale of trust units	$ 350,000
	Repayment of borrowings outstanding under PCEC s senior secured credit agreement and second lien credit agreement	
	Distributions to equity owners of PCEC	
	Payment of underwriting discounts, structuring fee and other offering expenses	
	Cash proceeds remaining	$

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(b)	Reduction of oil and natural gas properties due to conveyance of Net Profits Interests:	
	Historical cost of Underlying Properties	$ 421,207
	Less: Asset retirement obligations	(22,300)
	Property to be conveyed to the Trust	398,907
	Multiplied by percentage allocable to Net Profits Interests(1)	80%
	Historical cost of oil and natural gas properties conveyed to the Trust	319,126
	Multiplied by portion of trust units sold to public	%
	Reduction in oil and natural gas proved properties due to conveyance of Net Profits Interests to the Trust	$
	Accumulated depletion, depreciation and amortization of Underlying Properties	$ (93,846)
	Multiplied by percentage allocable to Net Profits Interests(2)	80%
	Accumulated depletion, depreciation and amortization of oil and natural gas properties conveyed to the Trust	(75,077)
	Multiplied by portion of trust units sold to public	%
	Reduction of accumulated depletion, depreciation, and amortization due to the conveyance of Net Profits Interests to the Trust	$

(1) There was no historical cost or retirement obligation allocated to Remaining Properties.

(2) All accumulated depletion, depreciation and amortization was attributable to the Developed Properties.

(c)	Gain on sale of Net Profits Interests calculated as follows:	
	Gross cash proceeds from sale of trust units	$ 350,000
	Less: Net book value of conveyed Net Profits Interests	
	Plus: PCEC retained interest in trust units (%)	
	Payments of underwriting discounts, structuring fees and other offering expenses	
	Gain on sale of units	$

The gain on sale of units has been excluded from the unaudited pro forma statement of operations as the item is non-recurring.

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The pro forma adjustments included in the unaudited pro forma statement of operations are as follows (in thousands):

		Year Ended December 31, 2011
(d)	Calculation of net profits:	
	Revenues of the Underlying Properties	
	Oil sales	$ 105,871
	Natural gas	938
	Total revenues	106,809
	Direct operating expense of the Underlying Properties:	
	Direct lease operating expense	34,613
	Production and property taxes	3,110
	Total direct operating expenses	37,723
	Development costs[1]	29,901
	Total expenses and development costs	67,624
	Excess of revenues over direct operating expenses and development costs	39,185
	Multiplied by percentage allocable to Net Profits Interests[2]	80%
	Profit	31,348
	PCEC operating and services fee[3]	(1,000)
	Net profits to Trust from Net Profits Interests	30,348
	Multiplied by portion of trust units sold to the public	%
	Reduction in PCEC s total revenues due to Net Profits Interests of public unit holders	$

(1) Per the terms of the Net Profits Interests, development costs are to be deducted when calculating the distributable income to the Trust.

(2) Includes no revenues or expenses attributable to the Remaining Properties.

(3) In connection with the closing of this offering, the Trust will enter into an operating and services agreement with PCEC that obligates the trust to pay to PCEC a monthly fee for operating and informational services to be performed by PCEC on behalf of the trust relating to the Conveyed Interests. The monthly fee will be an amount equal to $83,333.33, which fee will change on an annual basis commencing on April 1, 2013, based on changes to the CPI.

As the Net Profits Interests burden the conveyed properties with no obligation by the holder to pay expenses, the Net Profits Interests are treated as royalty payments, with the associated amounts shown as a reduction of PCEC s revenues.

		Year Ended December 31, 2011
(e)	Reduce depreciation on assets conveyed to Trust	$ 7,557

(f) Interest expense adjustment reflects partial repayment of borrowings under the revolving credit facility with the proceeds from the offering of trust units.

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ANNEX A

January 30, 2012

Mr. Mark L. Pease

BreitBurn Management Company, LLC

600 Travis Street, Suite 4800

Houston, Texas 77002

Dear Mr. Pease:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2011, to the Pacific Coast Energy Company LP (PCEC) interest in certain oil and gas properties located in California and referred to herein as the Underlying Properties . The Underlying Properties include the Orcutt properties located onshore in the Santa Maria Basin and the East Coyote, Sawtelle, and West Pico properties located onshore in the Los Angeles Basin. 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 PCEC. A proposed net profits interest in such reserves is to be conveyed later this year to Pacific Coast Oil Trust with an effective date of April 1, 2012; the effect of the proposed conveyance is not accounted for in these estimates. 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 PCEC 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.

We estimate the net reserves and future net revenue to the PCEC interest in the Underlying Properties, as of December 31, 2011, to be:

Category	Net Reserves Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Future Net Revenue (M$) Total	Present Worth at 10%
Proved Developed Producing	18,360.1	11.5	3,359.5	714,892.6	385,495.5
Proved Developed Non-Producing	2,175.8	0.0	98.7	157,944.0	78,252.5
Total Proved Developed	20,535.9	11.5	3,458.2	872,836.6	463,748.0
Proved Undeveloped	12,594.1	178.2	1,393.2	642,982.5	197,778.4
Total Proved	33,130.0	189.6	4,851.4	1,515,819.1	661,526.4

Totals may not add because of rounding.

The oil reserves 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.

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Gross revenue is PCEC s share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for PCEC s share of production taxes and ad valorem taxes, capital costs, abandonment costs, payments to net profits interests, and operating expenses 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 2011. For oil and NGL volumes, the average Energy Information Administration West Texas Intermediate (Cushing) spot price of $95.97 per barrel is adjusted by lease for quality, transportation fees, and regional price differentials. For gas volumes, the average Henry Hub spot price of $4.118 per MMBTU is adjusted by lease 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 $95.45 per barrel of oil, $101.42 per barrel of NGL, and $3.452 per MCF of gas.

Operating costs used in this report are based on operating expense records of BreitBurn Management Company, LLC (BreitBurn). For nonoperated properties, these costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. As requested, operating costs for the operated properties are limited to direct lease- and field-level costs and BreitBurn s estimate of the portion of its headquarters general and administrative overhead expenses necessary to operate the properties. Operating costs have been divided into fixed field costs and variable per-well costs. As requested, the fixed field costs are allocated by year among the proved reserves categories based on the proportionate share of total proved future net revenue. Estimates of proved developed producing reserves and revenue are consequently dependent on BreitBurn completing the drilling and workover programs scheduled in this report. Operating costs are held constant throughout the lives of the properties.

Capital costs used in this report were provided by BreitBurn and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for recurring maintenance projects, workovers, new development wells, and production equipment. Based on our understanding of BreitBurn s future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are BreitBurn s estimates of the costs to abandon the wells and production facilities, net of any salvage value. Capital costs and abandonment costs are held constant to the date of expenditure.

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. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential gas volume and value imbalances resulting from overdelivery or underdelivery to the PCEC 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 PCEC receiving its net revenue interest share of estimated future gross gas 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

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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 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 PCEC, BreitBurn, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting geoscience, performance, and work data are on file in our office. The titles to the properties have not been examined by NSAI, nor has the actual degree or type of interest owned been independently confirmed. 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

Date Signed: January 30, 2012

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

Date Signed: January 30, 2012

JCH:LRG

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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.

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DEFINITIONS OF OIL AND GAS RESERVES

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

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

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DEFINITIONS OF OIL AND GAS RESERVES

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

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

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DEFINITIONS OF OIL AND GAS RESERVES

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

(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.

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DEFINITIONS OF OIL AND GAS RESERVES

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

(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.

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DEFINITIONS OF OIL AND GAS RESERVES

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

(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

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DEFINITIONS OF OIL AND GAS RESERVES

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

(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).

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DEFINITIONS OF OIL AND GAS RESERVES

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

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.

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DEFINITIONS OF OIL AND GAS RESERVES

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

(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.

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ANNEX B

March 9, 2012

Mr. Mark L. Pease

BreitBurn Management Company, LLC

600 Travis Street, Suite 4800

Houston, Texas 77002

Dear Mr. Pease:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2011, to the proposed net profits and overriding royalty interest to be owned by Pacific Coast Oil Trust (PCOT) 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 a proposed net profits and overriding royalty interest currently owned by Pacific Coast Energy Company LP (PCEC) will be conveyed later this year to PCOT with an effective date of April 1, 2012, and that the proved reserves estimated in this report constitute all of the proved reserves to be owned by PCOT. Our report dated January 30, 2012, sets forth our estimates of proved reserves and future revenue to the 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 net profits interests will entitle PCOT to receive 80 percent of the net profits from the sale of oil and natural gas production from proved developed reserves on the Underlying Properties and either 25 percent of the net profits from the sale of oil and natural gas production from proved undeveloped reserves on the Underlying Properties or a 7.5 percent overriding royalty interest in the proved undeveloped reserves of the Orcutt properties for periods when net profits are not available. 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.

We estimate the net reserves and future net revenue to the PCOT proposed interest in these properties, as of December 31, 2011, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed	7,742.3	5.2	1,431.1	699,976.1	358,809.2
Proved Undeveloped	1,820.1	16.2	163.3	181,366.0	68,462.8
Total Proved	9,562.4	21.4	1,594.4	881,342.1	427,272.0

Totals may not add because of rounding.

The oil reserves 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.

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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 proposed net profits interest are determined monthly using the economic interest method. By reserves category, the sum of the net profits payment and PCOT s proposed interest 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 proposed 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 2011. For oil and NGL volumes, the average Energy Information Administration West Texas Intermediate (Cushing) spot price of $95.97 per barrel is adjusted by lease for quality, transportation fees, and regional price differentials. For gas volumes, the average Henry Hub spot price of $4.118 per MMBTU is adjusted by lease 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 $94.04 per barrel of oil, $101.42 per barrel of NGL, and $3.480 per MCF of gas.

Because PCOT would own no working interest in these properties, operating costs and capital costs would not 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 are held constant throughout the lives of the properties, and capital costs are held constant to the date of expenditure. 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 would own 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 gas volume and value imbalances resulting from overdelivery or underdelivery to the proposed 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 proposed net profits interest share of estimated future gross gas 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

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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 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. (NSAI) and were accepted as accurate. Supporting geoscience, performance, and work data are on file in our office. The titles to the properties have not been examined by NSAI, nor has the actual degree or type of interest owned been independently confirmed. 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

Date Signed: March 9, 2012

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

Date Signed: March 9, 2012

JCH:LRG

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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.

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DEFINITIONS OF OIL AND GAS RESERVES

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

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.

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DEFINITIONS OF OIL AND GAS RESERVES

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

(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;

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DEFINITIONS OF OIL AND GAS RESERVES

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

(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.

DEFINITIONS OF OIL AND GAS RESERVES

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

(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

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DEFINITIONS OF OIL AND GAS RESERVES

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

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.

DEFINITIONS OF OIL AND GAS RESERVES

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

(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).

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DEFINITIONS OF OIL AND GAS RESERVES

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

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.

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DEFINITIONS OF OIL AND GAS RESERVES

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

(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.

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You should rely only on the information contained in this prospectus or in any free writing prospectus PCEC and the trust may authorize to be delivered to you. Until , 2012 (25 days after the date of this prospectus), federal securities laws may require all dealers that effect transactions in the trust units, whether or not participating in this offering, to deliver a prospectus. This is in addition to the dealers obligation to deliver a prospectus when acting as underwriters and with respect to their unsold allotments or subscriptions.

Trust Units

Prospectus

, 2012

Barclays

Citigroup

BofA Merrill Lynch

J.P. Morgan

UBS Investment Bank

Wells Fargo Securities

RBC Capital Markets

Baird

Stifel Nicolaus Weisel

Oppenheimer & Co.

Janney Montgomery Scott

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PART II

INFORMATION NOT REQUIRED IN PROSPECTUS

Item 13. ***Other Expenses of Issuance and Distribution.***

Set forth below are the expenses (other than underwriting discounts and commissions) expected to be incurred in connection with the issuance and distribution of the securities registered hereby. With the exception of the Securities and Exchange Commission registration fee, the FINRA filing and the NYSE listing fee, the amounts set forth below are estimates.

Registration fee	$ 48,433
FINRA filing fee	42,763
NYSE listing fee	162,000
Printing and engraving expenses	300,000
Fees and expenses of legal counsel	2,000,000
Accounting fees and expenses	975,000
Transfer agent and registrar fees	5,000
Trustee fees and expenses	213,500
Miscellaneous	1,153,304
Total	$ 4,900,000

Item 14. ***Indemnification of Directors and Officers.***

The trust agreement provides that the trustee and its officers, agents and employees shall be indemnified from the assets of the trust against and from any and all liabilities, expenses, claims, damages or loss incurred by it individually or as trustee in the administration of the trust and the trust assets, including, without limitation, any liability, expenses, claims, damages or loss arising out of or in connection with any liability under environmental laws, or in the doing of any act done or performed or omission occurring on account of it being trustee or acting in such capacity, except such liability, expense, claims, damages or loss as to which it is liable under the trust agreement. In this regard, the trustee shall be liable only for its own fraud, gross negligence or willful misconduct and shall not be liable for any act or omission of any agent or employee unless the trustee has acted in bad faith or with gross negligence in the selection and retention of such agent or employee. The trustee is entitled to indemnification from the assets of the trust and shall have a lien on the assets of the trust to secure it for the foregoing indemnification.

Under PCEC s limited partnership agreement and subject to specified limitations, no partner, officer or employee of PCEC will be liable for, and such partner, officer or employee will be indemnified and held harmless by PCEC against, any and all losses, liabilities and reasonable expenses, including attorneys fees, arising from proceedings in which such partner, officer or employee may be involved by reason of its being a partner, officer or employee. Subject to any terms, conditions or restrictions set forth in PCEC s limited partnership agreement, Section 17-108 of the Delaware Revised Uniform Limited Partnership Act empowers a Delaware limited partnership to indemnify and hold harmless any partner or other person from and against all claims and demands whatsoever. Reference is made to the Underwriting Agreement filed as an exhibit to this registration statement, which provides for the indemnification of PCEC, its managers and officers and any person who controls PCEC, including indemnification for liabilities under the Securities Act.

In connection with the preparation and filing of any registration statement pursuant to the registration rights agreement, PCEC will indemnify the trust and its agents from and against any liabilities under the Securities Act or any state securities laws arising from the registration statement or prospectus. PCEC will bear all costs and expenses incidental to any registration statement, excluding any underwriting discounts and fees.

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Item 15. ***Recent Sales of Unregistered Securities.***

None.

Item 16. ***Exhibits and Financial Statement Schedules.***

(a) *Exhibits.*

The following documents are filed as exhibits to this registration statement:

Exhibit Number	Description
1.1*	Form of Underwriting Agreement.
3.1	Certificate of Limited Partnership of Pacific Coast Energy Company LP.
3.2	Amendment to Certificate of Limited Partnership of Pacific Coast Energy Company LP.
3.3	Limited Partnership Agreement of Pacific Coast Energy Company LP.
3.4	Certificate of Trust of Pacific Coast Oil Trust.
3.5	Trust Agreement.
3.6	Form of Amended and Restated Trust Agreement.
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5.2*	Opinion of Latham & Watkins LLP.
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10.3	Form of Operating and Services Agreement.
10.4A #	Crude Oil Purchase Agreement, dated as of January 1, 2004, between Pacific Coast Energy Company (formerly ERG Operating Company, Inc.) and ConocoPhillips Company.
10.4B #	Amendment to Crude Oil Purchase Agreement, dated effective February 1, 2008, between Pacific Coast Energy Company (formerly BreitBurn Energy Company L.P.) and ConocoPhillips Company.
10.4C #	Amendment to Crude Oil Purchase Agreement, dated as of January 1, 2012, between Pacific Coast Energy Company and ConocoPhillips Company.
10.5 #	Amendment No. 5 to Crude Oil Outright Purchase Agreement, dated effective as of May 1, 2010, between Pacific Coast Energy Company LP (formerly BreitBurn Energy Company L.P.) and ConocoPhillips Company.
21.1	Subsidiaries of Pacific Coast Energy Company LP.
23.1*	Consent of PricewaterhouseCoopers LLP.
23.2*	Consent of PricewaterhouseCoopers LLP.
23.3	Consent of Richards, Layton & Finger P.A. (contained in Exhibit 5.1).
23.4	Consent of Latham & Watkins LLP (contained in Exhibit 8.1).
23.5*	Consent of Netherland, Sewell & Associates, Inc.
24.1	Powers of Attorney (included on the signature pages to the initial Registration Statement on Form S-1 filed on January 6, 2012).

Exhibit Number	Description
99.1	Summary Reserve Reports of Netherland, Sewell & Associates, Inc. (included as Annexes A and B to the prospectus).

  Previously filed.
* Filed herewith.
# Certain portions have been omitted pursuant to a confidential treatment request. Omitted information has been filed separately with the Securities and Exchange Commission.

(b) *Financial Statement Schedules.*

No financial statement schedules are required to be included herewith or they have been omitted because the information required to be set forth therein is not applicable.

Item 17. *Undertakings.*

The undersigned registrants hereby undertake:

(a) Insofar as indemnification for liabilities arising under the Securities Act of 1933 may be permitted to directors, officers and controlling persons of the registrants pursuant to the provisions described in Item 14, or otherwise, the registrants have been advised that in the opinion of the SEC such indemnification is against public policy as expressed in the Securities Act of 1933 and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the registrants of expenses incurred or paid by a director, officer or controlling person of the registrants in the successful defense of any action, suit or proceeding) is asserted by such director, officer or controlling person in connection with the securities being registered, the registrants will, unless in the opinion of their respective counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by them is against public policy as expressed in the Securities Act of 1933 and will be governed by the final adjudication of such issue.

(b) To provide to the underwriters at the closing specified in the underwriting agreement, certificates in such denominations and registered in such names as required by the underwriters to permit prompt delivery to each purchaser.

(c) For purpose of determining any liability under the Securities Act of 1933, the information omitted from the form of prospectus filed as part of this Registration Statement in reliance upon Rule 430A and contained in the form of prospectus filed by the registrants pursuant to Rule 424(b) (1) or (4) or 497(h) under the Securities Act shall be deemed to be part of this Registration Statement as of the time it was declared effective.

(d) For the purpose of determining any liability under the Securities Act of 1933, each post-effective amendment that contains a form of prospectus shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

(e) To send to each trust unitholder at least on an annual basis a detailed statement of any transactions with the trustees or their respective affiliates, and of fees, commissions, compensation and other benefits paid, or accrued to the trustees or their respective affiliates for the fiscal year completed, showing the amount paid or accrued to each recipient and the services performed.

(f) To provide to the trust unitholders the financial statements required by Form 10-K for the first full fiscal year of operations of the trust.

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SIGNATURES

Pursuant to the requirements of the Securities Act of 1933, as amended, the registrant has duly caused this registration statement to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Los Angeles, State of California, on April 19, 2012.

Pacific Coast Energy Company LP

By: PCEC (GP) LLC, its general partner

By: /s/ Randall H. Breitenbach
Randall H. Breitenbach
Chief Executive Officer

Pursuant to the requirements of the Securities Act of 1933, as amended this Registration Statement has been signed by the following persons in the capacities and the dates indicated.

Signature	Title	Date
/s/ Randall H. Breitenbach Randall H. Breitenbach	Chief Executive Officer of PCEC (GP) LLC and Board Representative (Principal Executive Officer)	April 19, 2012
* Halbert S. Washburn	President of PCEC (GP) LLC and Board Representative (Principal Executive Officer)	April 19, 2012
* James G. Jackson	Chief Financial Officer of PCEC (GP) LLC and Board Representative (Principal Financial Officer)	April 19, 2012
* Lawrence C. Smith	Controller of PCEC (GP) LLC (Principal Accounting Officer)	April 19, 2012
* Howard Hoffen	Board Representative	April 19, 2012
* Gregory D. Myers	Board Representative	April 19, 2012
* V. Frank Pottow	Board Representative	April 19, 2012

*By: /s/ Randall H. Breitenbach

Randall H. Breitenbach
Attorney-in-Fact

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Pursuant to the requirements of the Securities Act of 1933, as amended, the registrant has duly caused this registration statement to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Los Angeles, State of California, on April 19, 2012.

Pacific Coast Oil Trust

By: Pacific Coast Energy Company LP

By: PCEC (GP) LLC, its general partner

By: /s/ Randall H. Breitenbach
Randall H. Breitenbach
Chief Executive Officer

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INDEX TO EXHIBITS

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