PACIFIC ENERGY PARTNERS LP
Form 10-K
March 15, 2005

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

**FOR ANNUAL AND TRANSITION REPORTS PURSUANT TO SECTIONS 13 OR 15(d)
OF THE SECURITIES AND EXCHANGE ACT OF 1934**

(Mark One)

ý **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended December 31, 2004**

or

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

31345
(Commission File Number)

PACIFIC ENERGY PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

Delaware (State or jurisdiction of incorporation or organization)	**68-0490580** (I.R.S. Employer Identification No.)
5900 Cherry Avenue **Long Beach, California** (Address of principal executive offices)	**90805** (Zip Code)

562-728-2800
(Registrant's telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on which Registered
Common Units representing limited partner interests	New York Stock Exchange

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

Title of Each Class
None

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

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2). Yes ý No o

The aggregate market value of the common units held by non-affiliates of the registrant (treating directors and executive officers of the registrant and holders of 10% or more of the common units outstanding, for this purpose, as if they were affiliates of the registrant) as of June 30, 2004, the last business day of the registrant's most recently completed second fiscal quarter, was $496,257,691, based on a price per common unit of $26.04, the closing price of the common units as reported on the New York Stock Exchange on such date. There were 19,158,747 of the registrant's common units and 10,465,000 of the registrant's subordinated units outstanding as of February 28, 2005.

Documents incorporated by reference: None.

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References in this annual report on Form 10-K to "Pacific Energy Partners," "Partnership," "we," "ours," "us" or like terms refer to Pacific Energy Partners, L.P. and its subsidiaries.

References in this annual report on Form 10-K to our "General Partner" refer to Pacific Energy GP, Inc. prior to March 3, 2005, and from and after March 3, 2005 to Pacific Energy GP, LP and/or Pacific Energy Management LLC, the general partner of Pacific Energy GP, LP, as appropriate.

Glossary of Terms

In addition, the following is a list of certain acronyms and terms used throughout the document:

ANS	Alaskan North Slope
APC	Aurora Pipeline Company Ltd.
Bbl	Barrels
Bpd	Barrels per day
CPUC	California Public Utilities Commission
dark products	Crude oil, refinery feedstocks such as gas oil and heavy fuel oils
DOT	Department of Transportation
EUB	Alberta Energy and Utilities Board
FERC	Federal Energy Regulatory Commission
Frontier	Frontier Pipeline Company
LB Acquisition	The sale on March 3, 2005 by The Anschutz Corporation of its 36.6% interest in Pacific Energy Partners, L.P. to the Lehman Brothers Merchant Banking Group
LBMB	Lehman Brothers Merchant Banking Group
LBP	LB Pacific, LP
mbpd	One thousand barrels per day
NEB	Canadian National Energy Board
OCS	Outer Continental Shelf
PEG	Pacific Energy Group LLC
PEM	Pacific Energy Management LLC, the general partner of Pacific Energy GP, LP
PMT	Pacific Marketing and Transportation LLC
PPS	Pacific Pipeline System LLC
Predecessor	The group of entities consisting of PPS, PMT, RMPS and RPL, for which the financial data and results of operations are presented prior to the initial public offering on July 26, 2002
PT	Pacific Terminals LLC
RMC	Rangeland Marketing Company
RMPS	Rocky Mountain Pipeline System LLC
RNPC	Rangeland Northern Pipeline Company
RPC	Rangeland Pipeline Company
RPL	Ranch Pipeline LLC
RPP	Rangeland Pipeline Partnership
SEC	Securities and Exchange Commission
SJV	San Joaquin Valley
TAC	The Anschutz Corporation
WPSC	Wyoming Public Service Commission

Information Regarding Forward-Looking Statements

This annual report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, (the "Securities Act") and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). These forward-looking statements are identified as any statements that do not relate strictly to historical or current facts, including statements that use terms such as "anticipate," "assume," "believe," "estimate," "expect," "forecast," "intend," "plan," "position," "predict," "project," or "strategy" or the negative connotation or other variations of such terms or other similar terminology. In particular, statements, express or implied, regarding our future results of operations or our ability to generate sales, income or cash flow or to make distributions to unitholders are forward-looking statements. Forward-looking statements are not guarantees of performance. Such statements are based on management's current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or predict.

We caution you that the forward-looking statements in this Annual Report on Form 10-K are subject to all of the risks and uncertainties, many of which are beyond our control, incident to gathering, transporting, storing and distributing crude oil and other dark products and buying, gathering, blending and selling crude oil. Please see "Items 1 and 2 Business and Properties" below for a more detailed description of these risks and other factors that may affect the forward-looking statements. The risk factors could cause our actual results to differ materially from those contained in any forward-looking statement. You should not put undue reliance on these forward-looking statements. We disclaim any obligation to announce publicly the result of any revision to any of the forward-looking statements to reflect future events or developments.

Part I

ITEMS 1 and 2. Business and Properties

Overview

We are a publicly traded Delaware limited partnership formed in February 2002. On July 26, 2002, we completed an initial public offering of common units representing limited partner interests.

We are engaged principally in the business of gathering, transporting, storing, and distributing crude oil and related products in California and the Rocky Mountain region, which includes Alberta, Canada. We generate revenue primarily by charging tariff rates for transporting crude oil and related products on our pipelines and by leasing storage capacity. We also buy, blend and sell crude oil, activities that are complementary to our pipeline transportation business. Information about us, including our Annual Report on Form 10-K, quarterly reports on Form 10-Q, and current reports on Form 8-K that we file with, or furnish to, the Securities and Exchange Commission (the "SEC"), pursuant to Sections 13(a) or 15(d) of the Exchange Act, are accessible, free of charge, on our website, www.PacificEnergy.com, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Our website also includes our Corporate Governance Guidelines, Code of Business Conduct and Ethics and charters of our Audit Committee, Compensation Committee and Nominating and Governance Committee.

We hold a 100% ownership interest in Pacific Energy Group LLC ("PEG"), whose 100% owned subsidiaries consist of: (i) Pacific Pipeline System LLC ("PPS"), owner of Line 2000 and the Line 63 system, (ii) Pacific Terminals LLC ("PT"), owner of the Pacific Terminals storage and distribution system, (iii) Pacific Marketing and Transportation LLC ("PMT"), owner of the PMT gathering and blending system, (iv) Rocky Mountain Pipeline System LLC ("RMPS"), owner of the Western Corridor system and the Salt Lake City Core system, and (v) Ranch Pipeline LLC ("RPL"), the owner of a 22.22% partnership interest in Frontier Pipeline Company ("Frontier"), a Wyoming general partnership. Our AREPI pipeline was, until January 1, 2004, owned by Anschutz Ranch East Pipeline LLC, which had been a 100% owned subsidiary of PEG until it merged into RMPS on that date.

We hold a 100% ownership interest in PEG Canada GP LLC, the general partner of PEG Canada, L.P. ("PEG Canada"), the holding company of our Canadian subsidiaries. We own 100% of the limited partner interests in PEG Canada, whose 100% owned subsidiaries consist of (i) Rangeland Pipeline Company ("RPC"), which owns 100% of Aurora Pipeline Company Ltd. ("APC") and a partnership interest in Rangeland Pipeline Partnership ("RPP"), (ii) Rangeland Northern Pipeline Company ("RNPC"), which owns the remaining partnership interest in RPP, and (iii) Rangeland Marketing Company ("RMC"). RPP owns all of the assets that make up the Rangeland pipeline system except the Aurora pipeline, which is owned by APC.

We also own 100% of Pacific Energy Finance Corporation, co-issuer of our $7^1/_8$% Senior Notes due 2014 (the "Senior Notes").

We have organized the Partnership into two regional business segments: the West Coast Business Unit and the Rocky Mountain Business Unit.

We are managed by our General Partner, Pacific Energy GP, LP, a Delaware limited partnership, which, prior to its conversion to a limited partnership on March 3, 2005, was Pacific Energy GP, Inc., a corporation owned 100% by a subsidiary of The Anschutz Corporation ("TAC"). On March 3, 2005, TAC sold all of its interest in the General Partner to LB Pacific, LP ("LBP"), which was formed by the Lehman Brothers Merchant Banking Group ("LBMB") in connection with the purchase. The acquisition by LBP (the "LB Acquisition") included the 100% ownership interest in our General Partner, which owned (i) the 2% general partner interest in the Partnership and the incentive distribution rights, and (ii) 10,465,000 subordinated units of the Partnership representing a 34.6% limited partner interest in us. Immediately prior to the closing of the LB Acquisition, Pacific Energy GP, Inc. was converted to Pacific Energy GP, LLC, a Delaware limited liability company; and immediately after the closing of the LB Acquisition, Pacific Energy GP, LLC was converted to Pacific Energy GP, LP. Immediately following the consummation of the LB Acquisition, our General Partner distributed the 10,465,000 subordinated units of the Partnership to LBP.

In connection with the conversion of our General Partner to a limited partnership, our General Partner ceased to have a board of directors, and is now managed by its general partner, Pacific Energy Management LLC, a Delaware limited liability company ("PEM"), which is 100% owned by LBP. PEM has a board of directors (the "Board of Directors" or "Board") that manages the business and affairs of PEM and, thus, indirectly manages the business and affairs of our General Partner and the Partnership. The Board of Directors is comprised of six of the directors who served on the board of directors of our General Partner prior to the LB Acquisition, together with four directors appointed by LBP. For further discussion of the Board of Directors, see "Item 10 Directors and Executive Officers". All of the officers and employees of our General Partner were transferred to fill the same positions with PEM, and the PEM Board established the same committees as had been maintained by our General Partner prior to the LB Acquisition. PEM also adopted our General Partner's compensation structure and its employee benefits plans and policies.

The chart that follows depicts the current organization and ownership of the Partnership.

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West Coast Business Unit

Our West Coast Business Unit, located in California, consists of two principal pipelines, Line 2000 and the Line 63 system, which transport crude oil produced in California's San Joaquin Valley and the California Outer Continental Shelf ("OCS") to refineries and terminal facilities in the Los Angeles Basin and in Bakersfield. These pipelines are the only common carrier pipelines delivering crude oil produced in the San Joaquin Valley and the two primary California OCS producing fields, Point Arguello and the Santa Ynez Unit, to the Los Angeles Basin and Bakersfield. We also own and operate the PMT gathering and blending system, a proprietary gathering and blending operation in the San Joaquin Valley, and the Pacific Terminals storage and distribution system, a crude oil and dark products storage and pipeline distribution system situated in the Los Angeles Basin that was purchased on July 31, 2003 from Southern California Edison Company ("SCE"). Our West Coast Business Unit is headquartered in Long Beach, California, with a field office in Bakersfield.

Recent Developments. We are developing a new deepwater petroleum import terminal and related storage and pipeline distribution facilities to handle marine receipts of crude oil and feedstocks in the Port of Los Angeles (the "Pier 400 Project"). In February 2004, we completed a feasibility study of the Pier 400 Project. We recently completed an updated cost estimate. We are estimating that Pier 400 will cost $185 million, which is subject to change depending on various factors, including: (i) the final scope of the project, which will reflect updated customer storage needs and the requirements imposed through the permitting process; and (ii) changes in construction costs. This cost estimate assumes the construction of 2.5 million barrels of storage, although we are seeking permits for up to 4.0 million barrels of storage. We have begun seeking the environmental and other permits that will be required for the Pier 400 Project from a variety of governmental agencies, including the Board of Harbor Commissioners, the South Coast Air Quality Management District, various agencies of the City of Los Angeles and the Los Angeles City Council. We expect to have the necessary permits in early 2006. We have entered into a project development agreement and terminal services agreement with two subsidiaries of Valero Energy Corporation, which provide for a long-term volume commitment of 50,000 bpd for 30 years to support the project. The agreements are subject to satisfaction of various conditions, including completion of a mutually satisfactory agreement for the allocation of costs that will be required for the mitigation of vessel emissions. We are negotiating similar long term off-loading and throughput agreements with other potential customers. We expect construction of the Pier 400 Project to be completed and placed in service in 2007. We anticipate funding of the remaining pre-construction costs to be incurred through the end of 2005 from our existing revolving credit facility. Construction of the terminal facility is expected to be financed through a combination of debt and proceeds from the issuance of additional partnership units, including common units.

Rocky Mountain Business Unit

Our Rocky Mountain Business Unit is comprised of the following assets, which form an integrated pipeline network:

Rangeland system

Western Corridor system (made up of varying ownership interests)

Salt Lake City Core system

Frontier pipeline (22.22% partnership interest)

These Rocky Mountain pipeline systems transport crude oil produced in Canada and the U.S. Rocky Mountain region to refineries in Montana, Wyoming, Colorado and Utah. Deliveries are also made to the refining and marketing center of Edmonton, Alberta from the Rangeland system. Deliveries of crude oil are made to refineries directly through our pipelines or indirectly through connections with third party pipelines. Our Rocky Mountain Business Unit is headquartered in Denver, Colorado with a marketing and operations office in Calgary, Alberta. We have five field offices in Wyoming and three in Alberta.

On May 11, 2004, we completed the acquisition of the Rangeland system, including Rangeland Marketing Company ("RMC"), for an aggregate purchase price of approximately US$118 million. The Rangeland system is located in Alberta, Canada and consists of approximately 800 miles of gathering and trunk pipeline. On June 30, 2004, we completed the acquisition of the Mid Alberta pipeline (the "MAPL pipeline") for aggregate consideration of approximately US$27 million. The MAPL pipeline is also located in Alberta, Canada and consists of approximately 138 miles of trunk pipeline. Following the acquisition, the MAPL pipeline assets were integrated into and are now operated as part of the Rangeland system.

For further discussion on these purchases see "Rocky Mountain Business Unit" below.

Business Strategy

Our principal business objective is to achieve sustainable long-term growth of cash distributions to our unitholders by being a leading provider of pipeline transportation, storage and other midstream services to the North American energy industry. We strive to operate safely, protecting the environment and the communities in which we operate, while maintaining the operational integrity of our facilities. We seek to realize our business objective by executing the following strategies:

Leverage our strategic position in core market areas to maximize throughput on our pipelines and utilization of our storage facilities. As the owner and operator of the only two common carrier crude oil pipelines transporting crude oil produced in the San Joaquin Valley and in the two primary California Outer Continental Shelf producing fields to the Los Angeles Basin and to Bakersfield, we believe that we are well positioned to capitalize on the changing and growing needs of the refineries that serve California, the largest gasoline market in the United States. We continually seek opportunities to increase the crude oil throughput on our pipelines, to maximize the utilization of our storage facilities and to increase the capacity of our storage facilities. We believe the strategic position of our California pipelines and storage facilities creates other acquisition and development opportunities that will help us maintain and increase our cash flows.

Our Rocky Mountain pipelines serve major markets in the U.S. Rocky Mountain region, which continue to have a growing population and an increasing demand for refined products. Our Rocky Mountain pipeline network is strategically situated to take advantage of increasing crude oil production in Canada and growing demand for refined products in Salt Lake City and throughout the U.S. Rocky Mountain region. We believe crude oil throughput on our pipelines and our revenue will increase as refinery demand in the region continues to grow and the supply of Canadian crude oil, including synthetic crude oil, increases to make up for a continuing decline in crude oil produced in the U.S. Rocky Mountain region.

Control our operating and capital costs while maintaining the safety and operational integrity of our assets. We focus on managing our costs, while fulfilling our responsibility to operate safely, to protect the environment and communities in which we operate, and to maintain the operational integrity of our assets.

Pursue strategic and accretive acquisitions and new development projects that enhance and expand our core business. We intend to pursue acquisitions of additional midstream assets, including pipelines and storage and terminal facilities that are accretive to our cash flow and complement our existing business, with an emphasis on opportunities where supply and demand imbalances exist or where demand is not being met. We believe midstream assets will continue to be available for purchase as the major integrated energy companies divest noncore assets. We have three principal objectives in pursuing acquisitions:

- provide for long-term growth in our cash distributions per unit;
- strengthen and enhance our two existing business units; and
- expand outside our two existing business units into new growth areas and into the refined products and natural gas storage and transportation segments of the energy industry.

We will also seek to capitalize on our experience in the development and construction of new midstream projects that are complementary to our core market assets.

We have been successful in the execution of this strategy of acquisition and development over the past several years and believe our acquisition history, reputation and development projects experience will provide us with attractive opportunities in the future. The following transactions and activities demonstrate our experience in acquisition and development:

- in February 1999, we completed the construction of Line 2000 at a cost of approximately $275 million;
- in May 1999, we acquired the Line 63 system in exchange for an interest in PPS;
- in June 2001, we acquired the ownership interest in PPS that was held by a third party, increasing our ownership interest in PPS to 100%, for approximately $47 million;
- in June 2001, we acquired the PMT gathering and blending system for approximately $14 million;
- in December 2001, we acquired an additional 9.72% partnership interest in Frontier for approximately $9 million, increasing our ownership interest to 22.22% from 12.5%;
- in March 2002, we acquired the Western Corridor and Salt Lake City Core systems for approximately $107 million;
- in July 2003, we acquired the Pacific Terminals storage and distribution system for approximately $173 million;
- in February 2004, we completed a feasibility study and commenced the next phase of development of our Pier 400 Project;
- in May 2004, we acquired the Rangeland system for approximately $118 million; and
- in June 2004, we acquired the MAPL pipeline for approximately $27 million.

Minimize our exposure to commodity price volatility. We have historically managed our business to minimize our direct exposure to volatile commodity prices. We do not take title to the crude oil we transport on our pipelines and store in our storage facilities, except with respect to our crude oil buying, gathering, blending and selling activities in California, which currently represents a small percentage of net revenue and for purchases in connection with the operation of the Rangeland system in Canada. The Rangeland system operates as a proprietary system and, accordingly, we take title to the crude oil, condensate and butane that is gathered and transported. However, over 90% of the purchase contracts have concurrent sales contracts with the same counterparty and only a net payment is made to settle the monthly activity, thereby minimizing commodity price and credit risks. We believe this strategy of minimizing our exposure to commodity price volatility will continue to enhance our ability to generate stable free cash flow.

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West Coast Business Unit

Market Overview

General Market Considerations. The market in Southern California for our pipelines and storage facilities is influenced by the operation of the refineries in California, particularly those in the Los Angeles Basin and in central California, including Bakersfield. The operational levels and maintenance schedules of the refineries in our operating locations impact demand for shipment of and storage of crude oil and other related products on our pipelines and in our storage facilities.

Sources of Demand. Refined products such as gasoline, diesel fuel, jet fuel and heating oil are derived from crude oil. Demand for refined products directly impacts the demand for crude oil. California consumes the most gasoline and jet fuel of any state in the United States.

California refineries have a combined crude oil refining capacity exceeding 1.9 million bpd, ranking the state third highest in the nation. They currently process approximately 1.8 million bpd of crude oil. California has three main refining centers, located in the Los Angeles Basin, Central California and San Francisco. Approximately 63% of this refining capacity, or 1.2 million bpd, is in the Los Angeles Basin and Central California areas that are served by our pipelines. The California refineries were designed to process San Joaquin Valley ("SJV") heavy crude oil and higher sulfur California Outer Continental Shelf ("OCS") crude oil, which are both transported by our pipelines. They compete for various supplies of crude oil, including crude oil that is produced in the fields we currently serve. To the extent crude oil from the areas we serve is transported to the San Francisco refineries, the refineries we serve will be required to obtain their crude oil from supplies that are not transported on our pipelines. These refineries were also designed to process Alaskan North Slope ("ANS") and foreign crude oil. In addition to meeting intrastate demand, California refineries also export refined products to the Arizona and Nevada markets. The populations of Arizona and Nevada are expected to grow significantly over the next 20 years, which in turn is expected to increase the demand for refined products.

Shell Oil Company recently announced that it is has entered into a definitive agreement to sell its Bakersfield refinery. Previously Shell intended to close the refinery. While we would benefit from a closure of the Shell refinery, we are also positioned to benefit from its sale to a third party and continued operation through delivery of additional volumes to the refinery and from the refinery to the Los Angeles Basin.

Sources of Supply. California ranks fourth in crude oil production in the United States, including production from the Federal OCS. In addition to the local California-produced crude oil, major ports in San Francisco and Los Angeles receive waterborne ANS and foreign crude oil.

We expect that there will continue to be natural production declines from the California fields we serve as the underlying reservoirs are depleted. In addition, declining ANS production may impact us in the future if shippers elect to replace ANS crude oil delivered to San Francisco area refineries with crude oil produced in the San Joaquin Valley and California OCS.

In the third quarter of 2004, producers began the development of the Rocky Point field in the California OCS with the drilling of the first of eight planned wells. The first well began production at the end of the third quarter of 2004, thereby increasing the supply of crude oil available to be transported by us into the Los Angeles Basin. We anticipate that a significant portion of any incremental California OCS production will be transported on our pipelines.

We expect that with the natural production declines from the California fields we serve, there will be growth of imports transported by marine vessels to the Los Angeles Basin. With the acquisition of our Pacific Terminals storage and distribution system and, if successful, our proposed development of the Pier 400 Project, we expect that we will be able to participate in this growth.

Line 2000

General. We own and operate 100% of Line 2000, an intrastate common carrier crude oil pipeline that transports crude oil produced in the San Joaquin Valley and California OCS to refineries and terminal facilities in the Los Angeles Basin. Line 2000 is a 130-mile, insulated trunk pipeline originating at our Emidio Pump Station in Kern County, California. Line 2000 delivers crude oil directly and indirectly to refineries and terminal facilities in the Los Angeles Basin. Because Line 2000 is insulated, the heavy crude oil can be transported on Line 2000 without re-heating or diluting it.

The design throughput capacity of Line 2000 is approximately 145,000 bpd and the permitted annual throughput capacity is 130,000 bpd. In 2004, approximately 81,200 bpd were transported on Line 2000. Line 2000 is capable of transporting multiple batches and grades of heavy crude oil.

Line 2000 currently transports SJV heavy crude oil, California OCS crude oil and mid-barrel crude oil. SJV heavy crude oil and mid-barrel crude oil are received at our Emidio Pump Station. California OCS crude oil is received from Plains All American Pipeline at Pentland Station in Kern County, California and transported to Emidio Pump Station through a pipeline we lease from a third party.

Tariffs. The California Public Utility Commission ("CPUC") regulates tariffs on Line 2000. The tariff rates we charge shippers on Line 2000 are market-based rates, subject to certain limitations under contracts with certain of our shippers. The CPUC reviews our tariff rates when changes are sought. Under our long-term transportation agreements, we may raise our tariff rates in response to increases in various inflation-based indices and market factors. On May 1, 2004, we increased the tariff rates on Line 2000 by approximately 6%, based on the contractually agreed index of cost changes.

The Line 63 System

General. The Line 63 system is an intrastate common carrier crude oil pipeline system that transports crude oil produced in the San Joaquin Valley and California OCS to refineries and terminal facilities in the Los Angeles Basin and in Bakersfield. The Line 63 system consists of a 107-mile trunk pipeline, originating at our Kelley Pump Station in Kern County, California and terminating at our West Hynes Station in Long Beach, California. The Line 63 system includes 60 miles of distribution pipelines in the Los Angeles Basin and in the Bakersfield area, 156 miles of gathering pipelines in the San Joaquin Valley, and 22 storage tanks with approximately 1.2 million barrels of storage capacity. These storage assets, the majority of which are located in the San Joaquin Valley, are used primarily to facilitate the transportation of the crude oil on the Line 63 system. Line 63 has a throughput capacity of approximately 105,000 bpd. In 2004, approximately 60,000 bpd were transported to the Los Angeles Basin on Line 63.

Line 63 transports California OCS crude oil and multiple grades of SJV light crude oil, but does not transport any unblended heavy crude oil. We receive California OCS crude oil from the Plains All American Pipeline at Pentland Station in Kern County, California and SJV light crude oil at various receipt locations along the Line 63 gathering system. Line 63 transports crude oil for third-party shippers as well as crude oil received from our PMT gathering and blending system.

Tariffs. The CPUC regulates tariffs on the Line 63 system. The tariff rates we charge shippers on Line 63 are cost-of-service based. Cost-of-service based rates are developed and based upon the various costs to operate and maintain the pipeline, as well as charges for the depreciation of the capital investment in the pipeline and the authorized rate of return. Effective November 1, 2004, we increased the tariff rates 9.5% on our Line 63 system. This increase in tariff rates was the first for Line 63 since 2001.

Pacific Terminals Storage and Distribution System

General. The Pacific Terminals storage and distribution system complements our existing pipeline operations and forms one of the most extensive storage and pipeline distribution systems in southern California, providing service to all major refineries in the Los Angeles Basin.

PT's storage assets include 34 storage tanks with a total of approximately 9.0 million barrels of storage capacity. Of this total capacity approximately 6.7 million barrels are in active commercial service, 0.5 million barrels are used for "throughput" from marine vessels to other tanks and do not generate revenue independently, approximately 1.5 million barrels are idle but could be reconditioned and brought into service, and approximately 0.3 million barrels are in displacement oil service. We use the Pacific Terminals storage and distribution system to service the storage and distribution needs of the refining, pipeline and marine terminal industries in the Los Angeles Basin. In addition, PT has 17 storage tanks with a total of approximately 0.4 million barrels of storage capacity that are out of service. We have no current plans to bring these tanks into service. We have filed an application with the CPUC to sell approximately $10 million of idle PT land.

PT's pipeline distribution assets consist of 70 miles of distribution pipelines that are in active service and 49 miles of pipelines that are out of service. The active pipelines connect the PT storage assets with major refineries, our Line 2000 pipeline, and third-party pipelines and marine terminals in the Los Angeles Basin. An agreement that expires in October 2005, which provides for the use of a third-party dock in the Port of Long Beach, enables PT to receive crude oils and refinery feedstocks from, and export refinery feedstocks to, marine tankers. PT is capable of loading and off-loading marine shipments at a rate of 20,000 barrels per hour and transporting the product directly to or from certain refineries, other pipelines or its storage facilities. In addition, PT can deliver crude oil and feedstocks from its storage facilities to the refineries it serves at rates of up to 6,000 barrels per hour. We expect that we will be able to extend the October 2005 agreement on terms that are materially similar to current terms.

PT generates revenue primarily by leasing storage tank capacity to major refiners in the Los Angeles Basin. Lease rates for storage tanks are negotiated with each customer, resulting in private contracts varying in length from approximately one month to several years, generally with automatic renewal provisions. The customer contracts generally provide for throughput and heating charges, depending on the customer's specific needs.

Rates. PT is regulated by the CPUC. The CPUC has, however, authorized PT to establish the terms, conditions and charges for its storage and distribution services through negotiated contracts with its customers.

PMT Gathering and Blending System

General. In addition to our primary pipeline operations, we are engaged in buying, gathering, blending and selling crude oil, activities that are complementary to our pipeline transportation business. Our PMT gathering and blending system is located in the San Joaquin Valley and consists of 103 miles of gathering pipelines as well as truck off-loading and blending facilities at six locations along our gathering system. Our PMT facilities have a total of approximately 0.3 million barrels of storage capacity and up to 51,000 bpd of blending capacity. A substantial portion of this system was constructed in 1983.

The primary functions of our PMT operations are buying, gathering and blending various grades of crude oil and natural gasoline, then transporting the blended product on Line 63 for sale to Los Angeles Basin refiners. We contract for third-party trucks to collect crude oil from remote areas that are not connected to our gathering system. In 2004, we gathered and blended approximately 17,100 bpd of crude oil. The blended crude oil is transported on Line 63 and sold in the Los Angeles Basin. An additional 5,200 bpd of trucked crude oil was gathered and delivered without blending to customers in the Los Angeles Basin or in the San Joaquin Valley. We generate net revenue from our blending activity by capturing the difference in price between the lower grade crude oil and the higher grade, blended crude oil.

Generally, we purchase only crude oil for which we have a corresponding sale agreement for physical delivery of the crude oil to a third party. Through this process, we seek to maintain a position that is substantially balanced between crude oil purchases and future delivery obligations. However, we are subject to basis risk in several areas: the cost of blending components may vary from the price of the blended product; the pricing of its sales barrels can vary from the cost of its gathered barrels; and for two short term contracts, the pricing of purchased barrels is a function of the West Texas Intermediate index, while sales are based on West Coast postings. We do not acquire and hold crude oil futures contracts or enter into other derivative contracts for the purpose of speculating on crude oil prices. Crude oil hedging is conducted on a limited basis to protect our inventory positions from major changes in market prices.

Rates. Our PMT gathering and blending system is a proprietary intrastate operation that is not regulated by the CPUC or the Federal Energy Regulatory Commission ("FERC").

Customers

Each of the following customers represent greater than 10% of transportation and storage revenue for our West Coast operations for 2004: BP America Production Company; ChevronTexaco; Shell Trading Company and Valero Marketing and Supply Company. We have ship or pay agreements, expiring in 2009, with two customers, ChevronTexaco and Shell Trading Company, whereby they have committed to ship minimum volumes on Line 2000 that represent approximately 52% of their actual 2004 volumes transported on Line 2000. These agreements mitigate the potential adverse consequences of our concentration of customers.

Competition

Generally, pipelines are the lowest cost method for land-based transportation of crude oil over long distances. Therefore, our principal competitors for large volume shipments in the areas we serve are other pipelines. Competition among common carrier pipelines is based primarily on transportation charges, access to crude supplies and customer demand for crude oil. Line 2000 and Line 63 are currently the only common carrier crude oil pipelines that transport crude oil produced in the San Joaquin Valley and in the two primary California Outer Continental Shelf producing fields to the Los Angeles Basin and Bakersfield. However, ExxonMobil owns and operates a proprietary crude oil pipeline from the San Joaquin Valley to its refinery in the Los Angeles Basin. This pipeline has historically operated at or near capacity. While it currently transports only ExxonMobil's crude oil, it is possible for this pipeline to become a common carrier that could compete for third-party shipments of crude oil to the Los Angeles Basin. We believe high capital requirements, stringent environmental laws and regulations and the difficulty of acquiring rights-of-way and related permits make it difficult for third parties to build new pipelines in the areas we serve in California.

Line 2000 and the Line 63 system serve refineries in the Los Angeles Basin and in Bakersfield. The shippers that use our pipelines also compete with refiners in the San Francisco Bay and the central California areas for crude oil produced in the San Joaquin Valley and the California Outer Continental Shelf. Since the refiners in central California, including Bakersfield, do not have access to alternative supplies of crude oil and have the lowest transportation costs due to their proximity to the producing fields, they will usually outbid other end-users, including San Francisco Bay and Los Angeles Basin refiners, to fulfill their requirements for San Joaquin Valley and California Outer Continental Shelf crude oil. As a result, the San Francisco Bay and the Los Angeles Basin refiners who do not have adequate supplies of proprietary production must compete for the remaining supply of these crude oil types. SJV crude oil transported to the San Francisco Bay results in a reduction in the amount of crude oil available for transportation on our pipelines. Our throughput and revenue will be adversely affected to the extent more SJV crude oil is transported to the San Francisco Bay rather than to the Los Angeles Basin.

In addition, we face some competition from trucks that deliver crude oil in several areas we serve. While truck transportation is not cost effective for long distance transportation, trucks can compete effectively for incremental and marginal volumes over shorter distances.

Our PMT operations face competition from other marketing companies as well as refineries and other end users, some of which may be our customers that purchase crude oil directly at the producing field.

Rocky Mountain Business Unit

Market Overview

Sources of Demand. The U.S. Rocky Mountain region, which includes Montana, Wyoming, Colorado and Utah, is one of the fastest growing regions of the country in terms of overall population growth. This sustained population growth should result in regional refined products consumption growth. The 16 refineries in the region consume nearly 600,000 bpd of crude oil.

While we transport crude oil that is delivered throughout the Rocky Mountain region, Salt Lake City, Utah is one of our primary markets. Utah is one of the fastest growing states in the country and Salt Lake City is its most populous city. Salt Lake City's strong population growth is expected to stimulate growth in refined product demand, particularly gasoline and distillate. Additionally, Salt Lake City refiners supply refined products to markets in Utah, Wyoming, Idaho, Oregon, Washington and Nevada.

Sources of Supply. The crude oil supplying the U.S. Rocky Mountain refining centers is a combination of Rocky Mountain and Canadian crude oil, including Canadian synthetic crude. We believe U.S. Rocky Mountain crude oil production will continue to decline and imports of Canadian crude oil, including synthetic crude, will increase to replace it and meet the growing demand for crude oil in the region.

One major source of the increase in crude oil production in western Canada is the increase in the production of Canadian synthetic crude oil. Canadian synthetic crude oil is crude oil produced from bitumen, a viscous substance abundant in the oil sand deposits in western Canada. Production of Canadian synthetic crude is expected to increase in the future, which will benefit our Rocky Mountain operations in two ways: first, more Canadian synthetic crude should be available for transport on the pipelines for use by the U.S. Rocky Mountain refining centers, and second, more Canadian conventional crude oil could be transported on the pipelines as Canadian synthetic crude displaces it from other pipelines.

The acquisition of the Rangeland system in 2004 is a continuation of our regional development plans in the Rocky Mountains. The Rangeland system will allow us to participate in the expected increase in production of synthetic crude oil from the Alberta oil sands by providing Canadian producers and U.S. Rocky Mountain refiners with an integrated pipeline delivery system from Edmonton, Alberta to U.S. PADD IV markets.

Rangeland System

General. The Rangeland system includes the Rangeland pipeline and the MAPL pipeline. We own 100% of and operate the Rangeland system, although Imperial Oil currently provides certain operational services for the MAPL pipeline under a transition services agreement. The MAPL pipeline is a 138-mile proprietary pipeline with a throughput capacity of approximately 50,000 bpd if transporting light crude oil. The MAPL pipeline originates at Edmonton, Alberta and terminates in Sundre, Alberta, where it connects to the Rangeland pipeline. The Rangeland pipeline is a proprietary pipeline system that consists of approximately 800 miles of gathering and trunk pipelines and is capable of transporting crude oil, condensate and butane either north to Edmonton, Alberta via third-party pipeline connections or south to the U.S.-Canadian border near Cutbank, Montana, where it connects to the Western Corridor system. The trunk pipeline from Sundre, Alberta to the U.S.- Canadian border consists of approximately 250 miles of trunk pipelines and has a current throughput capacity of approximately 85,000 bpd if transporting light crude oil. The trunk system from Sundre, Alberta north to Rimbey, Alberta is a bi-directional system that consists of three parallel trunk pipelines: a 56-mile pipeline for low sulfur crude oil, a 63-mile pipeline for high sulfur crude oil, and a 56-mile pipeline for condensate and butane. From Rimbey, third-party pipelines move product north to Edmonton.

The existing Rangeland system serves a historic production area in Alberta, providing access to several types of conventional production resources. The MAPL pipeline provides a link between the Rangeland pipeline and the Edmonton oil hub. By using the MAPL pipeline, we will be able to access supplies of synthetic crude oil at Edmonton. We plan to develop new terminal facilities in Edmonton to maximize the use of the MAPL pipeline and the Rangeland system.

Tariffs. The Rangeland system operates as a proprietary system, and accordingly, we take title to the crude oil that is gathered and transported. Pursuant to a transportation service agreement between RMC and RPC, RMC has contracted for the entire capacity of the Rangeland pipeline. Customers who wish to transport crude oil, butane or condensate ("Product") on the Rangeland pipeline must either: (i) sell the Product to RMC at the inlet to the pipeline without repurchasing such Product from RMC; or (ii) sell the Product to RMC at an inlet point and repurchase such Product at agreed upon delivery points for the price paid at the inlet to the pipeline plus an established location differential. The significant majority of the volumes transported on the Rangeland system are conducted on the latter approach, mitigating commodity price volatility.

Substantially all of the pipelines that comprise the Rangeland system are subject to the jurisdiction of the Alberta Energy Utilities Board ("EUB"). The Rangeland system connects to the Western Corridor system at the U.S.-Canadian border via Aurora Pipeline, which is subject to the Canadian National Energy Board ("NEB"). Neither the EUB nor the NEB will generally review rates set by a crude oil pipeline operator unless it receives a complaint.

Location differentials on the Rangeland system are increased from time to time in response to market and competitive factors. On December 1, 2004, the location differentials were increased.

Western Corridor System

General. We own varying undivided interests in each of three contiguous pipelines that make up the Western Corridor system, an interstate and intrastate common carrier crude oil pipeline system. The Western Corridor system consists of 1,012 miles of pipelines extending from dual origination points at the Canadian border near Cutbank, Montana, where it receives deliveries from Rangeland pipeline and at Cutbank, Montana, where it receives deliveries from Cenex pipeline, and terminating in Guernsey, Wyoming, with connections in Wyoming to Frontier Pipeline, Suncor Pipeline, Platte Pipeline and our Salt Lake City Core system. Our ownership interest in each of the three pipelines comprising the Western Corridor system gives us rights to a specified portion of each pipeline's throughput capacity. The throughput capacity allocated to us is measured by reference to a volume of crude oil having certain viscosity characteristics; therefore our actual throughput capacity may be less if the crude oil being transported is more viscous, or heavier, than that which is used as the benchmark to determine the amount of throughput capacity. ConocoPhillips Pipe Line Company owns the remaining undivided interest in each of these pipelines. In 2004, approximately 76% of the crude oil transported on our portion of the Western Corridor system's throughput capacity was Canadian crude oil and the remaining 24% was Rocky Mountain crude oil. Our portion of the Western Corridor system does not currently transport Canadian synthetic crude, but we are currently working on new terminal facilities in Edmonton and constructing tanks in other locations to prepare for synthetic crude deliveries in the fourth quarter of 2005. The pipelines comprising the Western Corridor system were constructed at various times, with Glacier pipeline constructed in 1960, Beartooth pipeline in 1996 and segments of Big Horn pipeline in 1944 and 1996.

Each pipeline of the Western Corridor system is described below:

Glacier Pipeline. We own a 20.8% undivided interest in Glacier pipeline, which provides us with approximately 25,000 bpd of throughput capacity. Glacier pipeline consists of 565 miles of two parallel crude oil pipelines, a 277-mile, 12-inch trunk pipeline and a 288-mile, 8-inch and 10-inch trunk pipeline, both extending from the Canadian border and Cutbank, Montana to Billings, Montana. Shipments on Glacier pipeline can be delivered either to refineries in Billings and Laurel, Montana or into Beartooth pipeline. In 2004, approximately 15,200 bpd of Canadian crude oil was transported through our Glacier pipeline throughput capacity. Conoco Pipe Line Company is the operator of Glacier Pipeline.

Beartooth Pipeline. We own a 50% undivided interest in Beartooth pipeline, which provides us with approximately 25,000 bpd of throughput capacity. Beartooth pipeline is a 76-mile, 12-inch trunk pipeline from Billings, Montana to Elk Basin, Wyoming. All shipments on Beartooth pipeline are delivered into Big Horn pipeline. In 2004, approximately 9,800 bpd of Canadian crude oil was transported on our Beartooth pipeline throughput capacity. Beartooth pipeline was constructed to connect Glacier pipeline with Big Horn pipeline. We operate Beartooth pipeline.

Big Horn Pipeline. We own a 57.6% undivided interest in Big Horn pipeline, which provides us with approximately 33,900 bpd of throughput capacity. Big Horn pipeline consists of a 250-mile, 12-inch trunk pipeline from Elk Basin, Wyoming to Casper, Wyoming and a 121-mile, 12-inch trunk pipeline from Casper, Wyoming to Guernsey, Wyoming. Shipments on Big Horn pipeline can be delivered either to Wyoming refineries directly, into Frontier pipeline at Casper, Wyoming or into the Salt Lake City Core system, the Suncor Pipeline, or Platte Pipeline at Guernsey, Wyoming. In 2004, approximately 9,800 bpd of Canadian crude oil and 4,900 bpd of U.S. Rocky Mountain crude oil was transported on our Big Horn throughput capacity. We operate Big Horn pipeline.

Under our contracts with Conoco Pipe Line Company, we manage our undivided interest in the Western Corridor system independently of Conoco Pipe Line Company. We set our own tariff rates, market our own capacity to shippers and account for our own revenue. This information is not shared with Conoco Pipe Line Company. We approve and monitor budgets and are allocated our share of the costs in accordance with our joint agreement.

We also own various undivided interests in 22 storage tanks that provide us with a total of approximately 1.3 million barrels of storage capacity. These storage assets are used primarily to facilitate the transportation of the crude oil on our portion of the throughput capacity of the pipelines.

Tariffs. The FERC and the Wyoming Public Service Commission ("WPSC") each regulate various tariffs on the Western Corridor system. The tariff rates we charge shippers on the Western Corridor system are cost-of-service based tariffs, although competitive forces or shipper agreements may limit certain rates.

Salt Lake City Core System

General. We own 100% of and operate the Salt Lake City Core system, an interstate and intrastate common carrier crude oil pipeline system that transports crude oil produced in Canada and the U.S. Rocky Mountain region primarily to refiners in Salt Lake City. The Salt Lake City Core system trunk pipelines have a combined throughput capacity of approximately 114,000 bpd to Salt Lake City. In 2004, approximately 103,300 bpd was delivered to Salt Lake City directly through our pipelines and approximately 37,600 bpd was delivered indirectly through connections to a ChevronTexaco pipeline. The Salt Lake City Core system consists of approximately 955 miles of trunk pipelines, approximately 209 miles of gathering pipelines, and 32 storage tanks with approximately 1.5 million barrels of storage capacity. These storage assets are used primarily to facilitate the transportation of the crude oil on the pipelines. The main trunk pipeline originates in Ft. Laramie, Wyoming, receives deliveries from the Western Corridor system at Guernsey, Wyoming, and extends west to Wamsutter, Wyoming, where it divides, with a northern segment continuing west, eventually delivering to Salt Lake City, and a southern segment extending south to Rangely, Colorado, where it delivers to a ChevronTexaco pipeline that serves Salt Lake City. In 2004, the northern segment delivered approximately 40,100 bpd and the southern segment delivered approximately 18,000 bpd to Salt Lake City. In addition, 42,500 bpd were transported from Frontier/Evanston Station, Utah to Kimball Junction, Utah, 7,300 bpd were transported from Reno to Casper, Wyoming and 3,000 bpd from Reno to Guernsey, Wyoming. In 2004, a significant volume of the crude oil transported on the Salt Lake City Core system was Rocky Mountain crude oil. Construction of the Salt Lake City Core system began in 1939 with construction of additional pipelines and facilities continuing until 1991. In 2004, we completed a $3.4 million, 7,000 bpd expansion into Salt Lake City.

We also operate a trucking fleet that transports additional volumes for delivery into the Salt Lake City Core system. Our trucks transport crude oil owned by others from outlying producing fields throughout Wyoming, which for economic reasons, do not have a physical connection to one of our pipelines. The crude oil is gathered and then delivered to unloading stations along the Salt Lake City Core system. Our trucks also transport processed water for others from oil and gas wellheads to disposal sites. Our trucking operations do not represent a significant portion of our total operating income.

Tariffs. The FERC and the WPSC each regulate various tariffs on the Salt Lake City Core system. The tariff rates we charge on the Salt Lake City Core system are cost-of-service based tariffs, although competitive forces may limit such rates. The FERC tariff rates generally increase each July 1 by the amount of change in the Producer Price Index for finished goods.

Frontier Pipeline

General. We own 22.22% of Frontier Pipeline Company, a general partnership that owns 100% of Frontier pipeline, and we serve as its operator. Enbridge, Inc., an unrelated third party, owns the remaining 77.78% of Frontier Pipeline Company. Frontier pipeline is an interstate common carrier crude oil pipeline that consists of a 289-mile trunk pipeline with a throughput capacity of approximately 62,200 bpd and three storage tanks with approximately 274,000 barrels of storage capacity. These storage assets are used primarily to facilitate the transportation of the crude oil on the pipelines. Frontier pipeline originates in Casper, Wyoming, a hub for the distribution of crude oil produced in Canada and in the U.S. Rocky Mountain region, and receives deliveries from the Western Corridor system. Frontier pipeline also receives Canadian crude oil, including Canadian synthetic crude, via connections with Express pipeline, and other connecting carriers in Casper, Wyoming. Frontier pipeline delivers crude oil into the Salt Lake City Core system for ultimate delivery into Salt Lake City. In 2004, approximately 47,400 bpd was transported on Frontier pipeline. Frontier pipeline was constructed in 1983. We are the operator of the Frontier pipeline.

Tariffs. The FERC regulates tariffs on Frontier pipeline. The tariff rates we charge on Frontier pipeline are cost-of-service based tariffs, depending on the type and characteristics of the crude oil.

Customers

Each of the following customers represents greater than 10% of net revenue for our Rocky Mountain operations for 2004: ChevronTexaco, ConocoPhillips and Tesoro. We have not entered into any transportation contracts with respect to crude oil transported on the Rocky Mountain pipelines.

Competition

After acquiring the Rangeland system in 2004, we began developing an integrated crude oil transportation corridor from the Edmonton oil hub into the U.S. Rocky Mountain area. The Rangeland system competes with several pipelines for supplies of Canadian crude oil in the Edmonton area, including:

Enbridge System. The Enbridge system is a large mainline trunk pipeline system that gathers and transports a variety of crude oils east from the Edmonton area to markets in eastern Canada and the north-central region of the United States. The Enbridge system also connects to Express Pipeline and Bow River Pipeline at Hardisty, Alberta and the Wascana pipeline at Regina, Saskatchewan. These pipelines transport Canadian crude oil south to markets in Billings, Montana, Casper, Wyoming and various connecting carriers.

Terasen Trans Mountain System. Terasen Trans Mountain system transports Canadian crude oil from the Edmonton area to Canadian and U.S. West Coast markets.

The following pipelines and pipeline systems transport Canadian crude oil to refineries in the U.S. Rocky Mountain region, in competition with the Rangeland system and the our interests in the Western Corridor system:

Express/Platte Pipeline. Express/Platte Pipeline receives Canadian crude oil from the Enbridge system and other pipelines at Hardisty, Alberta and delivers to Frontier pipeline at Casper, Wyoming for further distribution to U.S. Rocky Mountain refineries. Express/Platte pipeline also transports Canadian crude oil to the PADD II market, its pipeline terminating at St. Louis, Missouri. In late 2003, Terasen Pipelines Inc., the partial owner and operator of the Express/Platte pipeline, announced it is expanding its total system capacity by 108,000 bpd from 172,000 bpd to 280,000 bpd. Its expanded service is scheduled to be ready in April 2005.

Wascana Pipeline; Eastern Corridor System. Wascana pipeline, which is connected to the Enbridge system at Regina, Saskatchewan, delivers Canadian crude oil and crude oil produced in eastern Montana and western North Dakota to the Eastern Corridor system, which delivers to the Salt Lake City Core system at Fort Laramie, Wyoming.

Bow River and Cenex pipelines. Bow River pipeline transports Canadian crude oil from Hardisty and production areas in southeastern Alberta to the Milk River Pipeline, which delivers to the Cenex Pipeline near the U.S.-Canadian border for delivery to Cutbank and Billings, Montana area refineries. Bow River Pipeline also interconnects with the Enbridge system at Hardisty, Alberta. Cenex Pipeline also delivers Canadian crude oil to the Western Corridor system at Cutbank, Montana.

Conoco Western Corridor System. Conoco Pipe Line Company owns an interest in the Glacier, Beartooth and Big Horn pipelines, which comprise our Western Corridor system. Conoco sets its own tariff rates, markets its throughput capacity and accounts for its revenue separate from and in competition with us.

We also compete against other pipelines on a local basis:

- *Central Alberta Pipeline.* In south central Alberta, the Central Alberta pipeline and the Rangeland system compete for the delivery of truck gathered conventional crude oil into the Edmonton market.

- *Rimbey, Bonnie Glenn and Pembina Pipelines*. The Rangeland system, which transports crude oil, condensate and butane south to the U.S. Rocky Mountain region, competes for supplies of crude oil, condensate and butane with Rimbey, Bonnie Glen and Pembina pipelines, which transport these products north to Edmonton.

- *Red Butte System*. The Red Butte system in eastern Wyoming gathers crude oil in the same area of Wyoming, namely Elk Basin, as our Big Horn gathering system.

The Rangeland system includes a number of crude oil gathering facilities referred to as Lease Automatic Custody Transfer ("LACT") points where it receives crude oil, condensate and butane from other connecting pipelines or truck gathered crude oil and condensate. Other companies can develop and operate similar facilities in competition with the Rangeland system.

Various companies have, for a number of years, discussed construction of a pipeline system to deliver refined products from El Paso, Texas, into the U.S. Rocky Mountain region. The purpose of such a pipeline would be to transport refined products from refineries in the Texas Gulf Coast to Salt Lake City via a series of connected pipeline segments. If built, such a pipeline would compete with our Rocky Mountain operations. Such a project would require extensive permitting, as well as significant modifications to existing pipelines and construction of new pipelines. Based on the information currently known to us, there is presently little interest being expressed for such a pipeline and it is not believed that it will be constructed in the near future.

We continue to face competition from trucks that transport crude oil produced in the Rocky Mountain region to local markets. We believe that despite their ability to transport incremental crude oil volumes from southwest Wyoming, trucks are not competitive for large volumes or longer distances. Moreover, we believe that the significance of truck competition will decline as Rocky Mountain crude oil production declines and is replaced by Canadian crude oil and synthetic crude oil.

Credit Risk

A majority of our business is conducted with major, high credit quality companies within the industry. We perform periodic credit evaluations of our customers' financial condition and generally do not require collateral for our services or for accounts receivables. In some cases, we require payment in advance or security in the form of a letter of credit or bank guarantee.

Pipeline Operation and Control

All of our U.S. pipelines are operated, monitored and controlled through our operations control center located at our main office in Long Beach, California. Our Canadian pipelines are operated, monitored and controlled through our operations control center in Olds, Alberta. Our operations control centers houses the pipeline system controller consoles and the Supervisory Control and Data Acquisition ("SCADA") systems used to operate the pipelines.

We operate all of our U.S. pipelines and the Frontier pipeline from four consoles that are manned 24 hours a day by our pipeline system controllers. Our Long Beach control center is housed in a stand-alone building designed with special earthquake protection and multiple security systems. This facility has two uninterruptible power supplies to provide continuous power in the event of an external power failure. It is also equipped with fire detection and fire suppression systems.

All of the Rangeland pipelines except the MAPL pipeline are remotely controlled and operated from a control center located in Olds, Alberta that is manned 24 hours a day. The MAPL pipeline is remotely controlled and operated 24 hours a day by Imperial Oil Resources pursuant to the transition services agreement we entered into upon purchasing the MAPL pipeline. The MAPL pipeline remote control and operation will be integrated into the Rangeland system concurrently with the start up of our Edmonton terminal, which is expected to be completed in the fourth quarter of 2005.

In general, the SCADA systems we use provide operational data, including product-specific information such as viscosity and gravity, and operational information, such as pressure, temperature and flow rates, as well as information on the operational condition of pumps, valves, tanks and other status points on a continuous, real-time basis. These SCADA systems also provide our pipeline system controllers with the ability to remotely control various aspects of systems operation, including starting and stopping pumps, opening and closing valves, and switching into and out of storage tanks.

Safety and Maintenance

We perform preventive and normal maintenance on our pipelines, tanks and other facilities and make repairs and replacements when necessary or appropriate. We also conduct routine and required inspections of our pipelines and other assets as required by law. We inject corrosion inhibitors into some of our pipelines to prevent internal corrosion. Cleaning and de-waxing devices, known as "pigs," are also run through most of our pipelines to help prevent internal corrosion, as further described below. External coatings and impressed current cathodic protection systems are used to protect against external corrosion on all trunk pipelines. We conduct all cathodic protection work in accordance with National Association of Corrosion Engineers standards. We continually monitor, test and record the effectiveness of these corrosion-inhibiting systems.

We monitor the structural integrity of selected segments of our pipelines through a program of periodic internal inspections using electronic internal inspection tools, or "smart pigs." These tools analyze the interior of our pipelines, providing data as to wall thickness, corrosion and other anomalies that might indicate possible pipeline failure. Our engineers conduct a detailed review of the inspection data and make repairs as required to ensure the integrity of the pipelines. We have developed an integrity management program in accordance with regulations for assessing our pipelines and prioritizing future smart pig runs or other approved integrity test methods. We believe this program will enable us to give the highest priority in scheduling inspections or pressure tests for integrity to pipelines with higher potential risk to the environment or the public.

In the five years ended December 31, 2004, we have internally inspected 100% of our California trunk pipelines and 35% of our distribution lines. During the same period, we smart pigged approximately 62% of the U.S. Rocky Mountain segment pipelines we operate and approximately 49% of our Rangeland trunk pipeline.

United States

Our U.S. pipelines are subject to regulation by the Department of Transportation ("DOT") under the Hazardous Liquids Pipeline Safety Act of 1979, as amended ("HLPSA"), relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. The HLPSA requires pipeline operators to comply with regulations issued pursuant to HLPSA, to permit access to and allow copying of records and to make certain reports and provide information as required by the Secretary of Transportation.

The Pipeline Safety Act of 1992 ("Pipeline Safety Act") requires the Research and Special Programs Administration of the DOT to consider environmental impacts, as well as its traditional public safety mandate, when developing pipeline safety regulations. The DOT's pipeline operator qualification rules require minimum qualification requirements for personnel performing operations and maintenance activities on hazardous liquid pipelines. DOT regulations require operators of pipelines in "High Consequence Areas", such as densely populated or ecologically sensitive areas, to conduct risk assessments, utilize internal inspection devices or perform hydrotesting to assess pipeline integrity, and facilitate changes in operation and maintenance procedures to reduce the risk of public safety and environmental impacts.

The Pipeline Safety Improvement Act of 2002, imposes additional requirements on pipeline operators. The act mandates, among other things, the delivery to the DOT of data that can be used in a national pipeline mapping system, the implementation of operator examinations and other qualification programs, periodic pipeline safety inspections, and increased civil penalties for violators. It also includes a whistleblower protection clause to protect line employees who reveal safety violations or operational flaws.

States are largely preempted by federal law from regulating pipeline safety but may assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. Some of the states in which we operate, including California, have assumed such responsibility for intrastate pipelines. Our trucking operations are also subject to safety and permitting regulation by the DOT and state agencies with regard to the safe transportation of hazardous and other materials by motor vehicle. We believe that our pipeline and trucking operations are in substantial compliance with applicable operational and safety requirements. Nevertheless, significant expenses could be incurred in the future if additional safety measures are required or if safety standards are raised and exceed the capabilities of our current pipeline control system or other safety equipment.

In California, our pipelines are subject to the Elder California Pipeline Safety Act of 1981, as amended, which in general implemented the HLPSA with respect to California intrastate pipelines and delegated responsibility for administration and enforcement of the HLPSA to the California State Fire Marshal. In addition, this act requires all pipelines to undergo a hydrostatic test or smart pig (electronic internal inspection) inspection every five years and requires the state fire marshal to maintain a list of all pipelines in the state that, because of the occurrence of certain types or numbers of reportable leaks during the previous three or five year period are considered to be "higher risk" pipelines. All pipeline segments that are included on the higher risk pipeline list are required to be tested more frequently than other pipelines, in some cases as often as annually.

The workplaces associated with our U.S. operations are subject to the requirements of the Federal Occupational Safety and Health Act ("OSHA"), and comparable state statutes that regulate worker health and safety. In addition, some states, including California and Utah, have received authorization to implement their own occupational safety and health programs in lieu of the federal program. We have an ongoing, comprehensive safety training program for our employees and believe that our operations are in material compliance with applicable occupational health and safety requirements, including general industry standards, record keeping requirements, monitoring of occupational exposure to regulated substances, and hazard communication standards.

Canada

Federal Regulation. APC's pipeline, which is less than one mile in length, and connects to the Western Corridor system at the U.S.-Canadian border, is subject to the jurisdiction of the Canadian National Energy Board ("NEB"). With respect to this segment, the Onshore Pipeline Regulations ("OPR"), passed pursuant to the National Energy Board Act (Canada), set out minimum requirements for all stages of a NEB-regulated pipeline's lifecycle. The Canadian Standards Association ("CSA") pipeline standards provide a technical basis for the OPR by setting out the minimum technical requirements for the design, construction, operation and abandonment of pipelines. The NEB participates with industry and other government agencies in the development and maintenance of these standards. If the NEB finds that a CSA pipeline standard requirement is not sufficient for the pipelines under its jurisdiction, it may impose more stringent requirements within its governing regulations.

The NEB conducts regular on-site safety inspections of the pipeline systems under its jurisdiction. NEB inspections officers are empowered to issue orders which could require a company to suspend hazardous activities and/or take measures to ensure the safety of the public and company employees, or the protection of property and the environment. The NEB may also order a company to repair, reconstruct or alter a part of a NEB-regulated pipeline. The NEB may further direct that until such work is done, that part of the pipeline is not to be used, or is to be used only in accordance with terms and conditions specified by the NEB.

Documentation and safety audits are conducted by NEB staff at company offices to review procedures and records, to verify compliance with the regulations, and to address any safety issues. These audits examine operations and maintenance manuals, emergency procedures, safety training programs, inspection, maintenance and training records, and other company practices. Each company under the NEB's jurisdiction is currently audited every two to four years. Audits may also be conducted in response to specific operational issues.

The NEB and Human Resources Development Canada, a department of the Government of Canada, have entered into an agreement whereby NEB staff administer Part II of the Canada Labour Code, which is the federal legislation governing occupational health and safety, for pipelines under the NEB's jurisdiction. This permits designations of certain NEB staff as Safety Officers for the occupational health and safety of pipeline company field employees.

Provincial Regulation. Most of the Rangeland system is subject to the jurisdiction of the Alberta Energy and Utilities Board ("EUB"). With respect to the portion of the Rangeland system and the MAPL pipeline regulated by the EUB, materials codes and standards are specified in the Pipeline Regulation (Alberta). The Pipeline Regulation constitutes a regulatory code covering technical aspects of all phases of pipeline construction and operation from design to abandonment. The Pipeline Regulation also addresses testing and reporting requirements. While the EUB has also endorsed CSA standards, the EUB has acknowledged that it will consider specific situations and assess the suitability of a standard for particular purposes.

The Pipeline Act (Alberta) provides that pipeline operators may be ordered to adopt remedial measures or to suspend operations where it appears to the EUB or its authorized representative that there has been contravention of permit or license terms or provisions of the Pipeline Act or regulations, or that a hazardous situation exists.

The workplaces associated with the operations of the systems under the jurisdiction of the EUB are subject to the requirements of the Occupational Safety and Health Act (Alberta), which regulates worker health and safety.

Tariff Rate Regulation

United States

Interstate Pipelines. Our interstate common carrier crude oil pipeline operations are subject to tariff rate regulation by the FERC under the Interstate Commerce Act. The Interstate Commerce Act requires that tariff rates for crude oil pipelines, which for tariff rate purposes includes refined product pipelines, (crude oil and refined products pipelines are referred to collectively as "petroleum pipelines" in this section), be just and reasonable and non-discriminatory. The Interstate Commerce Act permits challenges to proposed new or changed tariff rates by protest and challenges to tariff rates that are already on file and in effect by complaint. In a protest case, the FERC is authorized to suspend the effectiveness of the new or changed tariff rate for a period of up to seven months and to investigate the rate. If, upon the completion of an investigation, the FERC finds that the rate is unlawful, it may require the pipeline operator to refund to shippers, with interest, any difference between the new rates and the rates the FERC determines to be lawful, so long as they are equal to or greater than the pre-existing rates. In addition, the FERC may order the pipeline to change its tariff rates prospectively to the lawful level. In a complaint case, upon the appropriate showing, a successful complainant may obtain reparations for up to two years prior to the filing of the complaint, and the FERC may also order lower rates to be filed prospectively. In general, and except as discussed below with respect to indexed and "grandfathered" rates, petroleum pipeline tariff rates must be cost-of-service based, although settlement rates, which are tariff rates that have been agreed to by all shippers, are permitted. Market-based tariff rates may be permitted when the FERC determines that the carrier does not have significant market power in the relevant transportation markets.

The FERC has adopted a form of trended original cost methodology as the general methodology to be used in setting cost-of-service based tariff rates for petroleum pipelines. The FERC's methodology is similar to the depreciated original cost methodology generally used by the FERC to set rates for natural gas pipelines and electric utilities, with the primary difference being that under the petroleum pipeline methodology, the inflation component of the pipeline's equity return is extracted from the equity return and added to the pipeline's equity rate base. The write-up is then amortized over the life of the pipeline's property, similar to the recovery of depreciation.

In October 1992, Congress passed the Energy Policy Act of 1992. The Energy Policy Act deemed interstate petroleum pipeline rates in effect for the 365-day period ending on the date of enactment of the Energy Policy Act, or that were in effect on the 365th day preceding enactment and had not been subject to complaint, protest, or investigation during the 365-day period, to be just and reasonable under the Interstate Commerce Act. These tariff rates are commonly referred to as "grandfathered rates." The Energy Policy Act provides that a grandfathered rate may not be challenged by complaint except in the following limited circumstances:

- a substantial change has occurred since enactment of the Energy Policy Act in either the economic circumstances of the oil pipeline that were a basis for the rate or the nature of the services that were a basis for the rate;

- the complainant was contractually barred from challenging the rate prior to enactment of the Energy Policy Act and filed the complaint within 30 days of the expiration of the contractual bar; or

- the rate is challenged as being unduly discriminatory or preferential.

The Energy Policy Act further required the FERC to issue rules establishing a simplified and generally applicable ratemaking methodology for interstate petroleum pipelines and to streamline procedures in petroleum pipeline proceedings. On October 22, 1993, the FERC responded to the Energy Policy Act directive by issuing Order No. 561, which adopted a new rate-indexing methodology for interstate petroleum pipelines. Under the resulting regulations, effective January 1, 1995, petroleum pipelines were able to change their rates within prescribed ceiling levels that are tied to changes in the producer price index for finished goods, minus one percent. Tariff rate increases made under the index are subject to protest, but the scope of the protest proceeding is limited to an inquiry into whether the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs. The rate-indexing methodology is applicable to any existing tariff rate, including grandfathered rates and rates established after enactment of the Energy Policy Act.

In Order No. 561, the FERC said that as a general rule pipelines must utilize the indexing methodology to change their tariff rates. Indexing includes the requirement that, in any year in which the index is negative, pipelines must file to lower their rates if they would otherwise be above the reduced ceiling. However, a pipeline is not required to reduce its grandfathered rates below the level deemed just and reasonable under the Energy Policy Act. Under the indexing regulations, a pipeline can request a rate increase that exceeds index levels under a cost-of-service approach only after establishing a substantial divergence between the actual costs experienced by the pipeline and the rate resulting from application of the index. The FERC also retained market-based rates and settlement rates as alternatives, in certain specified circumstances, to indexing and the cost-of-service approach.

The FERC indicated in Order No. 561 that it would assess every five years how the rate-indexing method was operating. The FERC conducted the first such assessment in 2000. In an order issued December 14, 2000, the FERC concluded the existing index had closely approximated the actual cost changes in the petroleum pipeline industry and that use of the rate index continued to satisfy the mandates of the Energy Policy Act. The Association of Oil Pipe Lines petitioned for judicial review of that decision to the U.S. Court of Appeals for the District of Columbia Circuit ("D.C. Circuit"), arguing that the annual adjustment should be based on the full producer price index, without the one percentage point deduction. On March 1, 2002, the D.C. Circuit found that the FERC had not provided adequate justification for retention of the existing rate-index and remanded the case to the FERC for further proceedings. On February 20, 2003, the FERC issued an order on remand in which it changed the rate index to the producer price index for finished goods, but without the one percentage point deduction. The FERC made the change on a prospective basis, but allowed oil pipelines to recalculate their maximum ceiling rates as though the new rate index had been in effect since July 1, 2001.

Another development affecting petroleum pipeline ratemaking arose in Opinion No. 397, involving Lakehead Pipe Line Company, L.P., a partnership that operates a crude oil pipeline. In Opinion No. 397, the FERC concluded that Lakehead was entitled to include in calculating its rates an income tax allowance only with respect to the portion of its earnings that are attributable to its partners that are not individuals, rationalizing that income attributable to individuals would be subject to only one level of taxation. The parties subsequently settled the case, so there was no judicial review of the FERC's decision.

The FERC subsequently applied its Lakehead approach in proceedings involving SFPP, L.P. ("SFPP"). SFPP is a subsidiary of a publicly traded limited partnership engaged in the transportation of petroleum products. In the first proceeding, the FERC issued Opinion No. 435 in which the FERC, among other things, affirmed Opinion No. 397's determination that there should not be a corporate income tax allowance built into a petroleum pipeline's rates for income attributable to noncorporate partners. Several parties sought rehearing of various issues addressed in Opinion 435, including its decision on the income tax allowance issue. The FERC addressed the requests for rehearing in Opinion No. 435-A, issued on May 17, 2000, in Opinion No. 435-B, issued on September 13, 2001, and in two subsequent orders. Several parties filed for judicial review before the D.C. Circuit of one or more of the FERC's decisions in this proceeding. On review, the DC Circuit found the Lakehead policy to lack a reasonable basis, and vacated the portion of the FERC's rulings that permitted SFPP an income tax allowance in accordance with that policy. The court remanded the issue to the FERC for further consideration, and the FERC has since initiated a broader inquiry into the implications of the court's decision on other FERC-regulated companies. While the ultimate outcome of the income tax allowance issue and other questions that were remanded to the FERC by the D.C. Circuit in the SFPP case could reduce the maximum amount we could legally charge under our FERC regulated tariffs, we do not believe that any such ruling would have a material impact on our results of operations.

A second proceeding involving SFPP involves, among other issues, shippers' challenges to SFPP rates that were grandfathered under the Energy Policy Act. A hearing before a FERC administrative law judge concerning this proceeding commenced in October 2001. In June of 2003, the administrative law judge issued an order on the first phase of the proceeding, which addressed whether a substantial change in economic circumstances had occurred with respect to SFPP's grandfathered rates. On March 26, 2004, the FERC issued an order on exceptions in which the FERC ruled that a substantial change in economic circumstances had occurred with respect to most of SFPP's grandfathered rates.

The FERC's decision also found, however, that its ruling in Lakehead that a limited partnership is entitled to claim an income tax allowance only with respect to the portion of its earnings that are attributable to partners that are corporations would not, by itself, constitute a substantial change in economic circumstances. Instead, the effect of the Lakehead ruling would be considered with all other changes in economic circumstances. Some parties to that proceeding have sought rehearing of the FERC's order, and other parties have petitioned the D.C. Circuit for review of the order. We cannot predict at this time what effect this proceeding will have on the ability of parties to challenge grandfathered rates.

The FERC generally has not investigated interstate rates on its own initiative when those rates have not been the subject of a protest or a complaint by a shipper. A shipper or other party having a substantial economic interest in our rates could, however, challenge our rates. In response to such challenges, the FERC could investigate our rates. To the extent that a complainant challenged an interstate rate that is grandfathered under the Energy Policy Act, the complainant would have to first demonstrate a substantial change since the date of enactment of the Act, in either the economic circumstances or the nature of the service that formed the basis for the rate. A complainant could assert that the creation of Pacific Energy Partners, L.P. itself constitutes such a change. If the FERC were to find a substantial change in circumstances, then the grandfathered rates could be subject to detailed review. Upon review of grandfathered rates for which a substantial change has been shown and any non-grandfathered rates, the FERC could inquire into all costs that underlie the rates being charged, including operating expenses, the allocation of overhead costs, capital structure and rate of return and allowance for federal and state income taxes. If our rates were successfully challenged, the amount of cash available for distribution to unitholders could be materially reduced.

Intrastate Pipelines. The CPUC regulates the tariffs we charge shippers on Line 2000 and the Line 63 system. Line 2000 has market-based tariffs and the Line 63 system has cost-of-service based tariffs.

Cost-of-service based rates are calculated by determining our revenue requirement, which is based on the sum of (1) forecasted costs of operating and maintaining the pipeline and associated administrative and general costs during a test year period, (2) depreciation, (3) a return (*i.e.*, the authorized rate of return) on the depreciated, historical capital investment and capital additions in the pipeline facilities, and (4) the associated taxes. To establish a unit transportation rate, the revenue requirement is allocated across the test year's forecasted throughput. Generally, to change rates, the pipeline must show that there will be a change in its costs of operation or that its rate base (*i.e.*, its capital investment) has or will change during the test year or that the cost of capital associated with its return on investment has changed, either because of a change in risk or in the cost of capital in general, or that there will be a change in throughput. To change rates, the pipeline must file a rate application that is subject to review by the CPUC. A rate filing may be protested and set for hearing. Once the CPUC reviews the application and determines a revenue requirement, the revenue requirement is converted into a rate per barrel of forecasted throughput.

Market-based rates, on the other hand, are not dependent on the pipeline's operating costs or investment, or forecasted throughput. Rather, within certain limits, the pipeline is free to file for negotiated rates or rates based on its perception of what the market will bear. To qualify for market-based rates, the pipeline has to demonstrate to the CPUC that there is competition in the market it serves and that it does not have market power. The CPUC may put certain limits on the number of rate changes that can be made during the course of a year or on the percentage increase in rates that can occur in any one year. A pipeline with market-based rates must still make a filing with the CPUC to modify its rates, but this is usually done through an advice filing. The advice filing can be protested and set for hearing, but the grounds for protest should be more limited than for cost-of-service based rate filings since the CPUC has previously granted market-based rate authority to the pipeline. A market-based pipeline, such as Line 2000, does not have an approved rate base, an authorized rate of return on its investment or an approved operation and maintenance or administrative and general cost calculation. A market-based pipeline assumes the risk of changes in its throughput.

Under either cost-of-service based or market-based ratemaking, the pipeline must give the CPUC and its shippers at least 30-days notice of the proposed change in rates. For pipelines that are regulated on a cost-of-service basis, such as the Line 63 system, this notice may require the filing of a formal rate application. For pipelines with market-based rate authority, such as Line 2000, this notice frequently is in the form of an advice filing. So long as an increase in rates does not exceed 10% in any 12-month period, upon expiration of the 30-day notice period the pipeline is permitted to change rates and to use those rates prior to CPUC approval, unless the CPUC suspends the rate change and its use. By law, the CPUC is allowed to suspend a proposed change in rates for an additional 30-day period following the expiration of the 30-day notice period. After that, the pipeline is allowed to put the proposed rates into effect, but must refund with interest any portion of a rate change that is subsequently disallowed by the CPUC. A pipeline with either cost-of-service based or market-based rates may file for a rate increase that exceeds 10% per 12-month period, but it is not allowed to put the rates into effect prior to the CPUC approving the change.

The CPUC, on its own initiative or at the urging of a shipper or interested party, may commence its own proceeding to change or reduce rates or alter the terms and conditions of service. In addition, the legislature or the CPUC may modify ratemaking methodologies with resulting tariffs that generate lower revenue and cash flow.

In Decision 94-10-044, which authorized SCE to utilize its fuel oil pipeline facilities for services to third parties, the CPUC authorized SCE to negotiate and execute individual contracts with customers for storage, pipeline distribution and other utility services. In Decision 03-07-031, which authorized the sale of the EPTC assets to PT, the CPUC authorized us to continue the same methodology for establishing storage and transportation fees that it had authorized for SCE.

The portion of the Western Corridor system located in Montana is exclusively an interstate pipeline system, transporting Canadian crude oil. As such, it is not subject to the jurisdiction of the Montana Public Service Commission.

The WPSC regulates the tariffs and crude oil transportation rates charged for intrastate deliveries on Big Horn pipeline of the Western Corridor system and the Salt Lake City Core system. These tariffs are primarily cost-of-service based, but free-market and competitive factors can influence the tariffs as well.

Cost-of-service based rates are calculated by determining the sum of (1) the forecasted cost of operating and maintaining the pipeline and associated administrative and general costs, (2) a return on the capital investment in the pipeline facilities (*i.e.*, authorized rate of return) and (3) a recovery of such capital investment (*i.e.*, depreciation).

We operate the portion of the Salt Lake City Core system located in Colorado as a common carrier interstate pipeline system, transporting third-party shippers' crude oil to Salt Lake City, making no deliveries in Colorado. As such, the Salt Lake City Core system is not subject to the jurisdiction of the Colorado Public Utilities Commission.

The Salt Lake City Core system does make intrastate crude oil deliveries. However, Utah law does not regulate intrastate oil pipeline operations or their tariff rates as public utilities.

The adoption by us of a cost-of-service based tariff under federal or state law does not guarantee that we will recover all of our costs relating to a pipeline system or segment.

Canada

Federal Pipelines. The NEB Act provides that every oil pipeline is a common carrier and has the obligation to receive, transport and deliver all crude oil offered for transmission through its pipeline. The NEB has stressed that this kind of statutory duty, as imposed on a regulated undertaking, is a relative obligation, rather than an absolute one, and that it is determined on a test of reasonableness. Furthermore, the party subject to a common carrier obligation may be relieved of that obligation upon application to the NEB.

The Aurora pipeline, which is less than one mile in length, and connects to the Rangeland system and to the Western Corridor system at the U.S.-Canadian border, is regulated by the NEB. Aurora is designated as a Group 2 company. The Group 2 companies operate smaller pipelines and have always been regulated more lightly than their Group 1 counterparts. That is, the NEB has not traditionally looked into their affairs unless it receives a complaint. However, it is of note that, without an NEB order permitting otherwise, the Aurora pipeline is subject to the jurisdiction of the NEB and is automatically designated as a common carrier. As a consequence, the pipeline proprietor is prohibited from discriminating between sources of supply or in favor of oil in which it has an interest. Group 2 companies are subject to less extensive information filing requirements but are generally required to file annual audited financial statements. A Group 2 pipeline company is responsible for providing shippers and other interested parties with sufficient information to enable them to ascertain whether the tolls are reasonable or a complaint is justified. Tariffs containing new tolls, once filed with the NEB, automatically become effective.

Intra-provincial Pipelines. The EUB has jurisdiction over the majority of the Rangeland system. The Rangeland system is currently operated on a proprietary basis. The EUB does not review the transportation rates set by a crude oil pipeline operator unless a shipper makes a complaint to the EUB. However, the EUB may, with the appropriate approval from the Government of Alberta, declare a pipeline in the province to be a common carrier. Common carriers are prohibited from discriminating between sources of supply or in favor of crude oil in which they have an interest. Pricing disputes between common carriers and shippers can then be resolved by the EUB.

Environmental Regulation

United States

General. Our U.S. operations are subject to complex federal, state, and local laws and regulations relating to the protection of health and the environment, including laws and regulations which govern the handling and release of crude oil, other liquid hydrocarbon materials, and hazardous substances. Violation of these environmental laws and regulations can result in the assessment of significant administrative, civil and criminal fines and penalties, imposition of remedial obligations, and, in some instances, issuance of injunctions banning or delaying certain activities. We believe that our operations are in substantial compliance with applicable environmental laws and regulations. However, these laws and regulations are subject to frequent change at the federal, state and local levels, and the clear trend is to place increasingly stringent limitations on activities that may affect the environment. Therefore, we are unable to predict the ongoing cost of complying with these laws and regulations or their future impact on our operations.

There are also risks of accidental releases into the environment associated with our operations, such as leaks or spills of crude oil or hazardous substances from our pipelines or storage facilities. Such accidental releases could, to the extent not insured, subject us to substantial liabilities arising from environmental cleanup and restoration costs, natural resource damages, claims made by neighboring landowners and other third parties for personal injury, property damage and business interruption, and fines or penalties for any related violations of environmental laws or regulations.

Although we are entitled in certain circumstances to contractual indemnification from third parties for environmental liabilities relating to assets that we acquired from those parties, these indemnification rights are limited and, accordingly, we may be required to bear substantial environmental expenses.

Air Emissions. Our U.S. operations are subject to the federal Clean Air Act and comparable state and local statutes, rules and regulations. Amendments to the Clean Air Act enacted in 1990, as well as recent or soon to be adopted changes to state implementation plans implementing those amendments, require or will require most industrial operations in the United States to make capital expenditures in order to meet air emission control standards developed by the U.S. Environmental Protection Agency ("EPA"), and state and local environmental agencies. As a result of these amendments, our facilities are subject to increasingly stringent air emissions regulations, including requirements that some facilities install maximum or best available control technologies to reduce or eliminate regulated emissions. We anticipate, therefore, that we will incur certain capital expenses in the next several years for air pollution control equipment in connection with maintaining existing facilities and obtaining permits and approvals for new or acquired facilities. Although we can give no assurances, we believe implementation of these Clean Air Act requirements will not have a material adverse effect on our financial condition or results of operations.

We are subject in the United States to various state air emission regulations that can be more stringent than federal regulations under the Clean Air Act. For example, our California operations are subject to the California Clean Air Act ("CCAA"). Under the CCAA, the California Air Resources Board has established state ambient air quality standards and toxic air contaminants requirements that are sometimes more restrictive and broader in scope than federal requirements. In California, for non-vehicular sources, compliance with the Federal Clean Air Act and the CCAA is under control of local air districts, which adopt rules and regulations affecting the stationary sources within their jurisdictions. The local air quality regulations tend to be more stringent than the federal regulatory requirements in areas where air quality standards have not been achieved, such as the San Joaquin Valley and the Los Angeles area. Local air districts also adopt their own regulations for toxic air contaminants. All of our facilities have active permits to operate from the local air districts. These permits set forth specific conditions that may limit the throughput or the types of material that may be treated, transported or stored.

Hazardous Substances and Waste Management. The Federal Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), also known as the "Superfund" law, and similar state laws, impose liability without regard to fault or the legality of the original conduct, on certain classes of persons, including the owners or operators of sites where hazardous substances have been released into the environment and companies that disposed or arranged for disposal of hazardous substances found at such sites. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to threats to public health or the environment at such disposal sites and to seek recovery of the costs they incur from the responsible classes of persons. Although "petroleum" is currently excluded from CERCLA's definition of a "hazardous substance," in the course of our ordinary operations we may handle some materials that fall within the definition of a "hazardous substance." We may, therefore, be subject to joint and several strict liability under CERCLA for all or part of any costs required to clean up and restore sites at which such materials have been released into the environment. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Analogous state laws may apply to a broader range of substances than CERCLA and, in some instances, may offer fewer exemptions from liability. We have not received any notification that we may be potentially responsible for cleanup costs under CERCLA or similar state laws.

Our U.S. operations also generate both hazardous and nonhazardous wastes that are subject to the requirements of the federal Resource Conservation and Recovery Act, as amended ("RCRA"), and comparable state statutes. We are not currently required to comply with a substantial portion of RCRA's requirements as our operations generate minimal quantities of hazardous wastes. From time to time, however, the EPA has considered making changes in nonhazardous waste standards that would result in stricter disposal requirements for these wastes, including certain crude oil wastes. Furthermore, it is possible that some of the wastes we generate that are currently classified as nonhazardous may in the future be reclassified as "hazardous wastes," which would trigger more rigorous and costly disposal requirements. Any such regulatory changes could result in an increase in our maintenance capital expenditures and operating expenses. In addition, analogous state and local laws may impose more stringent waste disposal requirements or apply to a broader range of wastes.

Water. The Federal Water Pollution Control Act, as amended, also known as the Clean Water Act, and similar state laws place strict limits on the discharge of contaminants into federal and state waters. Regulations under these laws prohibit such discharges unless authorized by and in compliance with a National Pollutant Discharge Elimination System ("NPDES"), permit or an equivalent state permit. The Clean Water Act and analogous state laws allow significant penalty assessments for unauthorized releases of water pollutants and impose substantial liability for the costs of cleaning up spills and leaks into the water. On June 1, 2003, we received an expedited information request from the EPA regarding a crude oil release that occurred on February 11, 2003 in Sublette County, Wyoming. We own a crude oil transportation pipeline in Sublette County that was discovered on February 11, 2003 to have released approximately 350 barrels of crude oil into a dry arroyo and thus we responded to the information request in a letter dated June 30, 2003. As reported to the EPA in our June 30, 2003 letter, all of the spilled crude oil was contained before it could enter or affect any body of water and the impacted soils were remediated by March 31, 2003. We have received no correspondence from EPA in response to our June 30, 2003 letter. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of stormwater runoff from certain types of facilities. State laws may also place restrictions and cleanup requirements on the release of pollutants into groundwater. Costs may be incurred in developing and implementing stormwater pollution prevention plans and spill prevention, control and countermeasure plans. We believe that we will be able to obtain, or be covered under, any required Clean Water Act permits and plans and that compliance with the conditions of those permits and plans will not have a material effect on our financial condition or results of operations.

The Oil Pollution Act, as amended ("OPA"), was enacted in 1990 and amends parts of the Clean Water Act and other statutes as they pertain to the prevention of and response to oil spills. Under the OPA, we could be subject to strict, joint and potentially unlimited liability for removal costs and other consequences of an oil spill from our facilities into navigable waters, along shorelines or in an exclusive economic zone of the United States. The OPA also imposes certain spill prevention, control and countermeasure requirements, such as the preparation of detailed oil spill emergency response plans and the construction of dikes or other containment structures to prevent contamination of navigable or other waters in the event of an oil overflow, rupture or leak. Some states, including California, have also enacted similar laws. We believe we are in material compliance with these laws.

Endangered Species Act. The Federal Endangered Species Act, as well as similar state laws, restrict activities that may affect threatened or endangered animal or plant species or their habitats. Some of our California facilities are located in, or pass through, areas that include or are designated as critical habitat for certain endangered species. Therefore, the Fish and Wildlife Service of the U.S. Department of the Interior has issued a Biological Opinion for Ongoing Maintenance Activities, which contains specific covenants related to our crude oil pipelines in these critical habitat areas. We believe that we are in compliance with the covenants of this opinion regarding the Endangered Species Act.

Site Remediation. We own or lease and in the past owned or leased a number of pipelines, gathering systems and storage facilities that have been used to store or distribute crude oil for many years, most of which were previously owned and operated by third parties whose handling, disposal or release of crude oil and wastes were not under our control. While our past operating and waste disposal practices were standard for our industry at the time, historical spills and releases along or at our properties by us and by previous owners and operators of our assets have resulted in soil contamination and may have resulted in groundwater contamination in some locations. Such contamination caused by historical activities is not unusual within the petroleum pipeline industry. We or previous owners have conducted site investigations at a number of these properties to assess environmental issues, including soil and groundwater conditions. Any historical contamination found on, under or originating from our properties may be subject to CERCLA, RCRA and analogous state laws as described above, and Canadian laws as described below. Under these laws, we could incur substantial expense to remediate any such contamination, including contamination caused by prior owners or operators. We currently do not have any active regulatory mandated or voluntary assessment, monitoring or remediation programs at company-owned facilities in the United States. In connection with our acquisitions, we have assumed the following liabilities representing the estimated cost of remediating the properties acquired: (i) in connection with the acquisition of ARCO Pipe Line Company ("ARCO")'s ownership interest in PPS in 2001, we assumed the cost of remediating the properties that had been contributed to PPS by ARCO in 1999, estimated at $2.6 million, (ii) in connection with the acquisition of the PMT assets in 2001, we assumed the liability for estimated remediation costs pursuant to a final agreement entered into on September 2, 2003, estimated at $0.1 million, and (iii) in connection with the acquisition of the storage and pipeline distribution assets from EPTC on July 31, 2003, we assumed certain environmental remediation costs, estimated at $2.7 million. However, there is no guarantee that the actual remediation costs or associated liabilities will not exceed these amounts.

Canada

General. All phases of the oil industry in Canada are subject to environmental regulation pursuant to a variety of Canadian federal, provincial, and municipal laws and regulations. Such laws and regulations impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of hazardous substances and wastes and in connection with spills, releases and emissions of various substances to the environment. These laws and regulations also require that properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Failure to comply with these environmental laws and regulations could result in the assessment of administrative, civil or criminal penalties and, in some instances, the issuance of injunctions to limit or cease operations.

We believe that our Canadian operations are in substantial compliance with applicable environmental laws and regulations. However, these laws and regulations are subject to frequent change and the clear trend is to place increasingly stringent limitations on activities that may affect the environment. Therefore, we are unable to predict the ongoing cost of complying with these laws and regulations or their future impact on our operations.

Air Emissions. In December 2002, the Canadian federal government ratified the Kyoto Protocol to the United Nations Framework Convention on Climate Change, which requires Canada to reduce its greenhouse gas emissions to 6% below 1990 levels over the 2008-2012 period. Although the Canadian government has not yet provided significant guidance on how it intends to meet these reduction targets, the energy industry has been identified as one of the areas that will be affected through the Large Industrial Emitters program.

Hazardous Substance and Waste Management. Our Alberta-based operations are subject to the Environmental Protection and Enhancement Act (Alberta) and associated regulations. Any release of a substance into the environment, which includes water, land and air, in an amount, concentration or rate that may cause a significant adverse effect, is prohibited, unless authorized by regulation or by an approval. Where a substance that has caused or may cause an adverse environmental effect is released into the environment, the person responsible for the substance must, as soon as that person becomes aware of the release, take all reasonable measures to remedy and confine the effects and remove or dispose of the substance so as to maximize environmental protection. No person may dispose of a hazardous substance except in accordance with an approval, a code of practice, registration or as otherwise provided for under the Act.

The Canadian Fisheries Act is primarily concerned with management of aquatic resources and particularly the protection of fish and fish habitat from damage. The Fisheries Act prohibits the release of a deleterious substance in water frequented by fish, without the necessary approvals. The Canadian Environmental Protection Act ("CEPA") is intended to ensure uniform national standards for the life cycle control and management of toxic substances. "Toxic" is a broadly defined term, and the list of substances identified in the regulations as "toxic" is constantly being updated. Regulations may be implemented under CEPA to establish emissions standards for toxic pollutants, including national ambient air quality objectives and national emission guidelines. Reporting and remedial requirements are placed on persons who own or control spilled toxic substances or who cause or contribute to their initial release. Canadian governmental officials may take remedial action and recover clean-up costs from the persons responsible.

Wildlife. The Canadian Species at Risk Act, the Canadian Migratory Birds Convention Act, and Alberta's Wildlife Act are designed to offer protection to specifically identified species. For example, the regulations under the Migratory Birds Convention Act make it an offence to release oil or other petroleum substances in or near waters frequented by migratory birds or on the ice of such water without an approval. The list of species protected pursuant to these statutes is constantly being updated.

Site Remediation. Any historical contamination found on, under or originating from our Canadian properties may be subject to the Environmental Protection and Enhancement Act (Alberta) and associated regulations. We could incur substantial expense to remediate any such contamination, including contamination caused by prior owners or operators. In addition there may be conditions contained in conservation and reclamation approvals issued in respect of the pipelines, which would require specific steps to be taken in the remediation of the pipeline sites. In connection with our acquisition of the Rangeland system on May 11, 2004, we recorded a Cdn$4.5 million (US$3.3 million) liability for estimated environmental remediation costs.

Title to Properties

United States

Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of the property. We have not received legal opinions or title insurance with respect to any of our rights-of-way. In many instances, lands over which rights-of-way have been obtained are subject to prior liens, which have not been subordinated to the right-of-way grants. We have permits, leases, license agreements and franchise ordinances from public authorities to cross over or under or to lay facilities in or along water courses, county roads, municipal streets and state highways, and in some instances, these permits are revocable at the election of the grantor. We also have license agreements from railroad companies to cross over or under railroad properties or rights-of-way, some of which are also revocable at the grantor's election. In some cases, property on which our pipeline was built is held under long-term leases or owned in fee.

In some instances the above rights-of-way are revocable at the election of the landowner. We potentially have, subject to various limitations in each state in which our pipelines are located, rights to condemn private property used in connection with our common carrier pipelines, thereby mitigating some adverse impact of any existing revocation rights. For example, in California, public utility pipeline companies may condemn private property subject to certain limitations and procedures, provided, that if such condemnation is for the purpose of competing with any entity offering the same competitive services, such company must obtain CPUC approval. In Montana, condemnation rights are available to common carrier crude oil pipeline companies that file appropriate documentation with the Montana Public Service Commission, which filing could subject such companies to additional regulation. In Colorado, a corporation (and possibly other forms of entities) formed for the purpose of constructing a pipeline may acquire a right of way by condemnation, provided that the corporation conforms to statutory condemnation procedures. In Utah and Wyoming, condemnation rights are available on behalf of the public use of crude oil pipelines, subject to certain limitations. Under Utah and Wyoming law, public or private entities may acquire easements by eminent domain for crude oil pipelines in accordance with specified statutory procedures.

All pump station properties for our common carrier pipelines are either on land that we own in fee, on property under a long-term lease or, in several cases, held under a Special Use Permit from the United States Department of the Interior. Our headquarters and control center are located on a 27.50-acre property in Long Beach that we own in fee. Crude oil storage tanks, maintenance facilities and warehouse space are also located on this property. Substantially all of the storage tank facilities operated by PT are on fee owned land. Our Bakersfield office and maintenance facility is located in a 15,000 square foot combination office space/warehouse building, occupied pursuant to a long-term lease. To support our Rocky Mountain operations, we have crude oil storage tanks and maintenance and warehouse facilities on land we own in fee in Casper, Wyoming. Our Evanston, Wyoming office and maintenance facility is occupied pursuant to a long-term lease.

We believe we have satisfactory title or other right to all of our material assets. Title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with acquisition of real property, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, and minor easements, restrictions, and other encumbrances to which the underlying properties were subject at the time of acquisition by our predecessor or us. However, we believe that none of these burdens will materially detract from the value of these properties or from our interest in these properties or will materially interfere with their use in the operation of our business.

Canada

The real property assets related to the Rangeland system fall into two basic categories of ownership: (i) properties underlying pumping stations and terminaling and storage facilities, which are owned in fee simple, and (ii) the properties underlying our Canadian pipelines, which are covered by leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for the construction and operation of pipeline assets. Such rights were acquired by voluntary negotiation and, in certain cases, through statutory rights of entry. There can be no assurance that legal challenges will not be brought with respect to the form, content or recording of such instruments or with respect to the compliance with the terms thereof. Generally, such instruments require the grantee to compensate the landowner or governmental authority for damages to such lands resulting from pipeline operations.

We believe we have satisfactory title or other right to all of the assets comprising the Rangeland system. Title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with acquisition of real property, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, and minor easements, restrictions, and other encumbrances to which the underlying properties were subject at the time of acquisition by our predecessor or us. However, we believe that none of these burdens will materially detract from the value of these properties or from our interest in these properties or will materially interfere with their use in the operation of our business.

Employees and Labor Relations

We do not have any employees, except in Canada. Pacific Energy Management LLC ("PEM") provides employees to conduct our U.S. operations. We and PEM collectively employ approximately 315 individuals who directly support our operations. We consider our employee relations to be good. None of these employees are subject to a collective bargaining agreement. PEM does not conduct any business other than with respect to the Partnership. All expenses incurred by our General Partner and PEM are charged to us.

Risks Inherent in Our Business

We may not have sufficient cash from operations to pay the minimum quarterly distribution following establishment of cash reserves and after payment of fees and expenses, including payments to our General Partner.

We may not have sufficient available cash each quarter to pay the minimum quarterly distribution on all units. The amount of cash we can distribute on our common units principally depends upon the amount of cash we generate from our operations. The amount of cash we generate from our operations will fluctuate from quarter to quarter and will depend upon, among other things:

- the volume of crude oil we transport through our pipelines;
- the tariff rates we charge on our pipelines;
- the percentage of storage capacity we have under lease;
- the lease rates we charge on our storage tanks;
- margins in our buying, gathering, blending and selling operations;
- the level of our operating costs, including payments to our General Partner;
- changes in currency exchange rates and foreign currency restrictions and shortages;
- the level of competition from other pipelines; and
- prevailing economic conditions.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, such as:

- the level of capital expenditures we make;
- the restrictions contained in our debt agreements and our debt service requirements;
- fluctuations in our working capital needs;

- the cost of acquisitions, if any;
- our ability to borrow under our working capital facility to make distributions; and
- the amount, if any, of cash reserves established by our General Partner, in its discretion.

The amount of cash we have available for distribution depends primarily on our cash flow, including cash flow from financial reserves and working capital borrowings, and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record a net loss and may not make cash distributions during periods when we record net income.

A material decline in the volume of crude oil processed by any of the refineries we serve could reduce our ability to make distributions to our unitholders.

Any significant reduction in the volume of crude oil processed at the refineries we serve could reduce the volume of crude oil we transport on our pipelines and result in our realizing materially lower levels of revenue and cash flow. This reduction could occur for a number of reasons, including:

- A sustained decrease in demand for refined products, which could result from:
  - a local or national recession or other adverse economic condition that results in lower spending by businesses and consumers on gasoline, diesel fuel and jet fuel;
  - an increase in the market price of crude oil that leads to higher refined product prices, resulting in lower demand;
  - higher fuel taxes or other governmental or regulatory actions that increase, directly or indirectly, the cost of gasoline or other refined products;
  - or a shift by consumers to more fuel-efficient or alternative fuel vehicles or an increase in fuel economy, whether as a result of technological advances by manufacturers, legislation mandating higher fuel economy or alternative fuel sources, or otherwise.
- Refineries we serve could partially or completely shut down their operations, temporarily or permanently, due to factors affecting their ability to produce refined products such as:
  - voluntary shutdown of a refinery for economic or other reasons;
  - unscheduled maintenance or catastrophic events at a refinery, such as a fire, flood, explosion or power outage;
  - labor difficulties that result in a work stoppage or slowdown at a refinery;
  - environmental litigation or other proceedings that require the halting of all or a portion of the operations at a refinery;
  - increasingly stringent environmental regulations, such as the Environmental Protection Agency's gasoline and diesel sulfur control requirements that limit the concentration of sulfur in motor gasoline and diesel fuel;
  - a governmental ban or other limitation on the use of any important feedstock or product of a refinery; or
  - other legislation or regulation that adversely impacts the economics of refinery operations.
- The refineries we serve may be unsuccessful in competing against other existing or future sources of refined products in their markets, such as pipelines or marine barges or tankers that deliver refined products into the Los Angeles Basin or the Rocky Mountain region from refineries in other areas.

A material decrease in the production of crude oil from the oil fields served by our pipelines could materially reduce our ability to make distributions to our unitholders.

The throughput on our pipelines depends on the availability of attractively priced crude oil produced from the oil fields served by our pipelines, or through connections with pipelines owned by third parties. Crude oil production may decline for a number of reasons, including natural declines due to depleting wells, a material decrease in the price of crude oil, or the inability of producers to obtain necessary drilling or other permits from applicable governmental authorities. If we do not replace volumes lost due to a temporary or permanent material decrease in production from the oil fields served by our pipelines, our throughput would decline, reducing our revenue and cash flow and adversely affecting our ability to make cash distributions to our unitholders.

Certain of the crude oil producing fields served by our pipelines are experiencing a decline in production. In addition, declining production may impact us in the future if shippers elect to replace Alaskan North Slope ("ANS") crude oil in San Francisco with crude oil produced in the San Joaquin Valley and California Outer Continental Shelf.

We may be unable to attract new volumes of crude oil, including Canadian synthetic crude oil, to the Rangeland and U.S. Rocky Mountain systems. In such an event, we may be unable to replace the crude oil production currently being gathered by these systems, which production is expected to decline.

A decrease in the price of crude oil, on either a temporary or permanent basis, may also affect the total volume of crude oil produced from the fields served by our pipelines. If crude oil prices were to decline significantly, as they did in 1998 and other periods in the past, production from certain of the fields served by our pipelines may cease to be profitable and crude oil producers may decide to decrease or stop production. In addition, an increase in the price of natural gas or electricity, both of which are used in connection with an advanced recovery technique known as steam-flooding, could result in a decrease in steam-flood operations in certain of the fields served by our pipelines and therefore reduce production. Natural gas is also used in the process of producing synthetic crude oil.

To maintain our throughput, new supplies of crude oil must be available to offset volumes lost because of declines in crude oil production. Replacement of lost volumes of crude oil is particularly difficult in an environment where production is declining and competition to gather available production is intense. It is difficult to attract producers to a new gathering system if the producer is already connected to an existing system. As a result, we or third-party shippers on our pipeline systems may experience difficulty acquiring crude oil at the wellhead in areas where there are existing relationships between producers and other gatherers and purchasers of crude oil.

If the refineries we serve process crude oil from locations to which our pipelines do not directly or indirectly connect, throughput on our pipelines could materially decline.

Throughput on our West Coast pipelines serving the Los Angeles Basin decreases to the extent refineries in the Los Angeles Basin choose to process more ANS and foreign crude oil and less California crude oil. Refineries in the Los Angeles Basin currently process crude oil produced in California, Alaska and various foreign nations. Marine barges and tankers deliver ANS and foreign crude oil to the Ports of Los Angeles and Long Beach. This crude oil is then directed through third-party pipelines to the various refineries and terminal facilities serving the Los Angeles Basin. These waterborne deliveries compete with crude oil produced in the San Joaquin Valley and California Outer Continental Shelf that is transported to the Los Angeles Basin on Line 2000 and the Line 63 system. To the extent waterborne deliveries reduce the demand for our transportation services, this decreases our West Coast operations' revenue and cash flow and could impair our ability to make distributions.

The refineries we serve may not be able to secure adequate supplies of crude oil from the crude oil producing areas served by our pipelines. For example, the refineries in the Los Angeles Basin that are served by our Line 2000 and Line 63 pipelines compete with refineries in the San Francisco Bay and central California areas for supplies of crude oil produced in the San Joaquin Valley and California Outer Continental Shelf; and to the extent this crude oil is directed to the San Francisco refiners, a decision over which we have no control, our throughput volumes and revenue would be adversely affected.

New competing pipeline systems could also be built or existing pipeline systems expanded that could deliver crude oil from other locations to the refineries that we serve. This could cause us to reduce our tariff rates or to experience reduced throughput.

If new sources of crude oil that are not connected to our pipelines become available to the refineries we serve, throughput on our pipelines could materially decline.

New sources of crude oil that are available to the refineries we serve could be discovered and developed. If a new source of crude oil is not connected to our existing pipelines, the throughput on our pipelines could materially decline. For example, wells have recently been successfully drilled and completed in a previously undeveloped oil field approximately one hundred miles south of Salt Lake City, an area that is not served by any of our pipelines. The extent of the oil reserves in this field are presently unknown, but if they are significant, they could compete with the oil expected to be delivered to the Salt Lake City refineries through our pipelines.

Due to our lack of asset diversification, adverse developments in our transportation and storage businesses could reduce our ability to make distributions to our unitholders.

We generate revenue primarily by charging tariff rates for transporting crude oil on our pipelines and by leasing capacity in our storage facilities. Due to our lack of asset diversification, an adverse development in one of these businesses would have a significantly greater impact on our financial condition and results of operations than if we operated more diverse assets.

Tariff rate regulation or a successful challenge to our tariff rates may reduce the tariff rates we charge and the amount of cash available for distribution to our unitholders.

The FERC regulates the tariff rates for our interstate common carrier operations. Shippers may protest our tariffs, and the FERC may investigate the lawfulness of new or changed tariff rates. The FERC may also investigate tariff rates that have become final and effective and require refunds of amounts collected under tariff rates ultimately found unlawful. The FERC's ratemaking methodologies may limit our ability to set rates based on our true costs or may delay the use of tariff rates that reflect increased costs.

In recent decisions involving unrelated oil pipeline limited partnerships, the FERC has ruled that these partnerships may not claim an income tax allowance for income allocable to non-corporate limited partners. In mid-2004, on review of one of those cases, the U.S. Court of Appeals for the District of Columbia Circuit held that the FERC's policy allowing even a partial income tax allowance for partnership pipelines had not been adequately justified and it remanded the issue to the FERC for further consideration. A shipper could rely on these decisions and claim that, because of the creation of the partnership, the income tax allowance used to calculate our interstate tariff rates should be reduced. If the FERC were to disallow the inclusion of all or part of the income tax allowance, it may be more difficult to justify some of our tariff rates. Any reduction in our tariff rates would most likely result in lower revenue and cash flows and may reduce our ability to make cash distributions to our unitholders.

Most of our U.S. intrastate pipeline and terminal operations are subject to regulation by state public utility commissions. A state commission may investigate our intrastate tariff rates or our terms and conditions of service on its own initiative or at the urging of a shipper or other interested party. If a state commission found that our tariff rates were not justified, the state commission could order us to reduce our tariff rates. If a state commission were to withdraw or modify our authority or use certain non-cost based rates, such as market based rates or the authority to negotiate or enter into individual customer contracts, our revenue and cash flows may be adversely affected, which could adversely affect our ability to make distributions to our unitholders.

Our Canadian pipelines are subject to regulation by the EUB and, in the case of the Aurora pipeline, the NEB. Under the National Energy Board Act, the Aurora pipeline is a common carrier. The NEB could investigate the tariff rates or our terms and conditions of service relating to the Aurora pipeline on its own initiative or at the urging of a shipper or other interested party and, if it found our rates or terms of service unjust or unreasonable or unjustly discriminatory, require us to reduce our rates, provide access to other shippers, or change our terms of service. The EUB could, on the application of a shipper or other interested party investigate the tariff rates or our terms and conditions of service relating to our proprietary pipelines and, if it found our rates or terms of service unreasonable or unjustly discriminatory, declare our pipelines to be common carrier pipelines and require us to reduce our rates, provide access to other shippers, or otherwise change our terms of service. Any reduction in our tariff rates would most likely result in lower revenue and cash flows and may reduce our ability to make cash distributions to our unitholders.

Our Canadian operations are subject to the jurisdiction of Canadian federal and provincial regulatory authorities.

The oil industry in Canada, including our operations, is subject to regulation and intervention by the Canadian federal and provincial regulatory authorities in such matters as environmental protection controls, control over the abandonment of pipelines, transportation rates and, possibly, expropriation or cancellation of contract rights. These regulatory authorities may impose regulations on or otherwise intervene in the oil industry with respect to prices, taxes, transportation rates and the exportation of oil. Such regulations may be changed from time to time in response to complaints or economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil industry could reduce demand for crude oil, increase our costs and may have a material adverse impact on our operations.

We may be unsuccessful in competing against existing or future pipelines in the areas in which we currently operate or may operate in the future.

Our principal competitors for large volume shipments of crude oil are other pipelines. For example, we compete with Express pipeline in transporting Canadian crude oil to the U.S. Rocky Mountain region. New crude oil pipelines could also be constructed in the areas served by our pipelines. Competition among common carrier pipelines is based primarily on transportation charges, access to producing areas and customer demand for crude oil. We compete to a lesser extent with trucks that deliver crude oil in several areas in which we serve. Some of our competitors have greater financial and other resources than we have. If we are unsuccessful in competing against other pipelines or trucking operations, throughput in our pipelines could be reduced and we may be unable to make cash distributions to our unitholders. Please read "Items 1 and 2 Business and Properties West Coast Operations Competition" and " Rocky Mountain Operations Competition" for a further discussion of the competition we face.

We are exposed to the credit risk of our customers in the ordinary course of our business.

In our buying, gathering, blending and selling business, when we purchase crude oil at the wellhead, we sometimes pay all or a portion of the production proceeds to an operator, who then distributes those proceeds to the various interest owners. This arrangement may expose us to operator credit risk, and we must determine whether the operators have sufficient financial resources to make these payments and distributions and to indemnify and defend us in case of a protest, action or complaint. Even if our credit review and analysis mechanisms work properly, we may experience losses in dealings with operators and other parties.

Our U.S. operations are subject to federal, state and local laws and regulations, including those relating to environmental protection, operations and safety, that could require us to make substantial expenditures.

Our U.S. operations are subject to federal, state and local laws and regulations relating to environmental protection, operations and safety. Many of these laws and regulations impose increasingly stringent permitting and operating requirements. In addition, these laws and regulations are subject to change, which change could result in an increase in our ongoing cost of compliance and have an adverse effect on our operations. We could, therefore, be adversely affected by increased costs due to stricter pollution control requirements or liabilities resulting from compliance with future required operating permits. Failure to comply with these environmental laws and regulations could result in the assessment of administrative, civil or criminal penalties and, in some instances, the issuance of injunctions to limit or cease operations.

There are risks of accidental releases associated with our operations, such as leaks or spills of crude oil from our pipelines or storage facilities, which could result in significant liabilities arising from environmental cleanup and restoration costs and claims for personal injury and property damage. If we were unable to recover such costs through insurance or increased tariff rates, cash distributions to our unitholders could be adversely affected.

We also own or lease a number of U.S. properties that have been used to store or distribute crude oil for many years. Crude oil and wastes associated with these historical activities may have been disposed of or released into the environment at these properties or at other locations where such materials may have been taken for disposal. In addition, most of these properties have been operated by third parties whose handling, disposal and release of crude oil and waste materials were not under our control. We could incur significant liabilities for cleanup and restoration costs and claims for personal injury and property damage related to these historical activities. Please read "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations."

Our U.S. operations are also subject to extensive operations and safety regulation. Many departments and agencies, both federal and state, are authorized by statute to issue and have issued rules and regulations binding on the crude oil industry and its individual participants. The failure to comply with these rules and regulations can result in substantial penalties. The regulatory burden on the crude oil industry increases our cost of doing business and, consequently, affects our profitability. Please read "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations."

Our Canadian operations are subject to Canadian environmental laws and regulations.

All phases of the oil industry in Canada are subject to environmental regulation pursuant to a variety of Canadian federal, provincial, and municipal laws and regulations. Such laws and regulations impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of hazardous substances and wastes and in connection with spills, releases and emissions of various substances into the environment. These laws and regulations also require that facility sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, changes to existing projects may require the submission and approval of environmental assessments or permit applications. Failure to comply with these environmental laws and regulations could result in the assessment of administrative, civil or criminal penalties and, in some instances, the issuance of injunctions to limit or cease operations. A release associated with the operation of the Rangeland system could result in significant liabilities arising from environmental cleanup and claims for personal injury or property damage.

The Rangeland system includes pipelines, gathering systems and storage facilities that have been used to transport and store crude oil for many years. Historical spills and releases from or at the

Rangeland system properties have resulted in soil and groundwater contamination in certain locations. Any historical contamination found on, under or originating from the properties may be subject to remediation requirements under Canadian laws or under our contracts with the sellers of the Rangeland system and the MAPL pipeline. In connection with our acquisition of the Rangeland system, we assumed a Cdn$4.5 million (US$3.3 million) liability for estimated environmental remediation costs. There can be no assurance that the actual remediation costs or associated liabilities will not exceed the amounts estimated above, or will not otherwise be significant.

In December 2002, the Canadian federal government ratified the Kyoto Protocol to the United Nations Framework Convention on Climate Change, which requires Canada to reduce its greenhouse gas emissions to 6% below 1990 levels over the 2008-2012 period. Although the Canadian government has not yet provided significant guidance on how it intends to meet these reduction targets, the energy industry has been identified as one of the areas that will be affected through the Large Industrial Emitters program. The final rules, once known, could affect our operations and profitability.

Our operations are subject to cross-border regulations

Our cross-border activities with our Canadian subsidiaries subject us to regulatory matters including export licenses, tariffs, Canadian and U.S. customs and tax issues and toxic substance certifications. Regulations include the Short Supply Controls of the Export Administration Act, the North American Free Trade Agreement and the Toxic Substances Control Act. Violations of these license, tariff and tax reporting requirements could result in the imposition of significant administrative, civil and criminal penalties. Furthermore, the failure to comply with U.S., Canadian, state and local tax requirements could lead to the imposition of additional taxes, interest and penalties.

Our operations are subject to operational hazards and unforeseen interruptions for which we may not be adequately insured.

Our operations are subject to operational hazards and unforeseen interruptions, such as earthquakes, landslides, floods and other natural disasters, accidents, fires, explosions, hazardous materials releases, acts of terrorism or other events beyond our control. A casualty might result in personal injury or loss of life, loss of equipment or loss of or extensive damage to property, as well as an interruption in our operations or the operations of the refineries to which we deliver. A significant portion of our assets are located in California, which has a high incidence of earthquakes. Many of our assets operate near rivers, streams, waterways, oceans, and other marine environments that are susceptible to greater damage and more costly cleanup in the event of a petroleum related release. In addition, we may not be able to maintain our existing insurance coverage or obtain new coverage of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies have increased substantially and could escalate further. Certain insurance is now or could become unavailable or available only for reduced amounts of coverage. For example, insurance carriers are now requiring broad exclusions for losses due to war risk and terrorist acts. We have elected not to extend our pollution liability insurance to cover terrorist attacks. Our other liability insurance has exclusions for certain types of terrorism. If we were to incur a significant liability for which we were not fully insured, it could adversely affect our business, financial condition or results of operations.

Any reduction in the capability of, or the allocations to our shippers on, connecting, third-party pipelines could cause a reduction of throughput on our pipelines and could reduce the amount of cash available for distribution to our unitholders.

We depend upon connections to third-party pipelines to deliver crude oil to some of our customers. Any reduction of capabilities in these connecting pipelines due to testing, line repair, reduced operating pressures, a decline in production associated with the third-party system or other causes could result in reduced throughput on pipelines. Similarly, any reduction in the allocations to our shippers on these connecting pipelines because additional shippers begin transporting volumes over the pipelines could also result in reduced throughput on our pipelines. Any reduction in throughput on our pipelines could adversely affect our revenue and cash flow and our ability to make distributions to our unitholders.

We are dependent on a small number of customers for a substantial portion of our revenue.

In 2004, the following customers represented greater than 10% of transportation and storage revenue for our West Coast operations: BP America Production Company; ChevronTexaco; Shell Trading Company and Valero Marketing and Supply Company. In addition, the following customers represented greater than 10% of net revenue for our Rocky Mountain operations: ChevronTexaco, ConocoPhillips and Tesoro. The loss of any of these customers, a decline in their credit worthiness or a substantial reduction in their shipments on our pipelines, could adversely affect our results of operations and cash flows and our ability to make distributions to our unitholders.

We are dependent on use of a third-party marine dock for delivery of waterborne products into our storage and distribution facilities in the Los Angeles Basin.

A portion of our storage and distribution business conducted in the Los Angeles basin is dependent on our ability to receive waterborne crude oil and other dark products, a major portion of which are presently being received through dock facilities operated by Shell Oil Products US in the Port of Long Beach. The agreement that allows us to utilize these dock facilities expires in October 2005, and there is no guarantee that it will be renewed. If this agreement is not renewed and if other alternative dock access cannot be arranged, the volumes of crude oil and other dark products that we presently receive from our customers in the Los Angeles Basin may be reduced, which could result in a reduction of storage and distribution revenue and cash flow and adversely affect our ability to make distributions to our unitholders.

Our ability to execute our acquisition or project development strategy may be impaired if we are unable to complete accretive acquisitions or projects on acceptable terms or access new capital to finance these activities.

Our ability to grow will depend principally on our ability to complete accretive acquisitions and development projects. We may be unable to identify attractive acquisition or project candidates or to complete acquisitions or projects on economically acceptable terms. Acquisition transactions can occur quickly and at any time and may be significant in size relative to the size of our existing asset base. We may need new capital to finance these acquisitions and development projects, and limitations on our ability to access new sources of capital may impair our ability to make acquisitions or undertake projects. If we are able to access new sources of capital, but only at more expensive rates, our ability to make accretive acquisitions or undertake projects will be limited. Our ability to maintain our capital structure may impact the market value of our common units.

The completion and success of our Pier 400 project remains subject to a number of risks unique to it, including (1) an exhaustive permitting process that may not result in the issuance of a permit and, even if successful, could result in the imposition of requirements and conditions that could adversely affect the feasibility and economic returns expected of the project, (2) political and legal risks posed by the many interest groups and constituencies that have an interest in the Port of Los Angeles and the project, one of which has declared its opposition to the project, (3) our ability to obtain the financing necessary to construct the project, which may depend on the ability to obtain other long-term commitments from creditworthy customers, which is not assured, and (4) the need to reach further agreement with Valero on a number of key issues related to the Pier 400 environmental mitigation facilities and cost commitments related thereto.

Our results of operations could be adversely affected by changes in currency exchange rates.

We operate in the United States and Canada and thus our financial results may be impacted by fluctuations in currency exchange rates. Significant fluctuations in the value of the Canadian dollar versus the U.S. dollar could materially affect our results of operations and financial condition.

Our ability to repatriate earnings from Canada may be limited by our Canadian revolving credit facility.

Our Canadian revolving credit facility contains restrictions on the distribution of funds by our Canadian operating subsidiaries to their U.S. parent company, PEG Canada, L.P. In the event of such restrictions, we may be adversely affected in our ability to make distributions to our unitholders.

Risks Inherent in an Investment in Us

Cost reimbursements to our General Partner, which are determined in our General Partner's sole discretion, may be substantial and reduce our cash available for distribution to you.

Our General Partner is entitled to be reimbursed for all expenses it incurs on our behalf and has sole discretion in determining the amount of these reimbursements. Our obligation to reimburse our General Partner for expenses may be substantial. These cost reimbursements to our General Partner reduce the amount of available cash for distribution to our unitholders. Our General Partner and its affiliates also may provide us other services for which we will be charged fees as determined by our General Partner.

Our General Partner's discretion in establishing cash reserves may reduce the amount of cash available for distribution to you.

Our partnership agreement requires our General Partner to deduct from operating surplus cash reserves that, in its reasonable discretion, are necessary to fund our future operating expenditures. In addition, our partnership agreement permits our General Partner to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party or to provide funds for future distributions to partners. These cash reserves affect the amount of cash available for distribution to you.

LBP and its affiliates have conflicts of interest with, and limited fiduciary responsibilities to, our unitholders, which may permit them to favor their own interests to your detriment.

As of December 31, 2004, TAC and its affiliates owned an aggregate 36.6% interest in us, consisting of the 2% general partner interest and a 34.6% limited partner interest. TAC owned our General Partner. On March 3, 2005, TAC sold its interest in us to LBP. LBMB controls 100% of LBP, which owns our General Partner. Based on our ownership, conflicts of interest may arise between LBP and its affiliates, including our General Partner, on the one hand, and us and our unitholders, on the other hand. As a result of these conflicts, our General Partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. These conflicts include, among others, the following situations:

- neither our partnership agreement nor any other agreement requires LBP to pursue a business strategy that favors us or utilizes our assets. The directors and officers of LBP have a fiduciary duty to make decisions in the best interests of the owners of LBP;

- LBP and its affiliates may engage in limited competition with us;

- our General Partner is allowed to take into account the interests of parties other than us, such as LBP, in resolving conflicts of interest;

- under Delaware law, our General Partner may limit its liability and reduce its fiduciary duties, while also restricting the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;

- our General Partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuances of additional partnership securities and cash reserves, each of which can affect the amount of cash, if any, that is distributed to our unitholders;

- our General Partner determines which costs incurred by it and its affiliates are reimbursable by us;

- our partnership agreement does not restrict our General Partner from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or entering into additional contractual arrangements with any of these entities on our behalf;

- our General Partner controls the enforcement of obligations owed to us by our General Partner and its affiliates; and

- our General Partner decides whether to retain separate counsel, accountants or others to perform services for us.

Our partnership agreement limits our General Partner's fiduciary duties to our unitholders and restricts the remedies available to unitholders for actions taken by our General Partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that waive or consent to conduct by our General Partner and its affiliates that reduce the obligations to which our General Partner would otherwise be held by state-law fiduciary duty standards. For example, our partnership agreement:

- permits our General Partner to make a number of decisions in its "sole discretion." This entitles our General Partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner;

- provides that our General Partner is entitled to make other decisions in its "reasonable discretion";

- generally provides that affiliated transactions and resolutions of conflicts of interest not involving a required vote of unitholders must be "fair and reasonable" to us and that, in determining whether a transaction or resolution is "fair and reasonable," our General Partner may consider the interests of all parties involved, including its own; and

- provides that our General Partner and its officers and directors are not liable for monetary damages to us, our limited partners or assignees for errors of judgment or for any acts or omissions if our General Partner and those other persons acted in good faith.

In order to become a limited partner of our partnership, a common unitholder is required to agree to be bound by the provisions in the partnership agreement, including the provisions discussed above.

Even if unitholders are dissatisfied, they cannot easily remove our General Partner, which could lower the trading price of the common units.

Our General Partner manages and operates us. Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business, and therefore limited ability to influence management's decisions regarding our business. Unitholders did not elect our General Partner or its Board of Directors and have no right to elect our General Partner or the Board of Directors on an annual or other continuing basis.

The Board of Directors is chosen by LBP. The directors of our General Partner have a fiduciary duty to manage our General Partner in a manner beneficial to LBP, the ultimate owner of our General Partner.

Furthermore, if unitholders are dissatisfied with the performance of our General Partner, they have little ability to remove our General Partner. Our General Partner generally may not be removed except upon the vote of the holders of at least $66^2/_3$% of the outstanding units voting together as a single class. Because LBP controls 35.3% of all the units representing limited partner interests, our General Partner currently cannot be removed without its consent. Also, if our General Partner is removed without cause during the subordination period and units held by our General Partner and its affiliates, including LBP, are not voted in favor of that removal, all remaining subordinated units will automatically be converted into common units and any existing arrearages on the common units will be extinguished. A removal of the General Partner under these circumstances would adversely affect the common units by prematurely eliminating their distribution and liquidation preference over the subordinated units, which preferences would otherwise have continued until we had met certain distribution and performance tests.

Cause is narrowly defined to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding our General Partner liable for actual fraud, gross negligence, or willful or wanton misconduct in its capacity as our General Partner. Cause does not include most cases of charges of poor management of the business, so the removal of our General Partner because of our unitholders' dissatisfaction with our General Partner's performance in managing our partnership will most likely result in the early termination of the subordination period.

Furthermore, unitholders' voting rights are further restricted by the partnership agreement provision which states that any units held by a person that owns 20% or more of any class of units then outstanding, other than our General Partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the Board of Directors, cannot be voted on any matter. In addition, our partnership agreement contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

As a result of these provisions, the price at which the common units trade may be lower because of the absence or reduction of a takeover premium in the trading price.

The control of our General Partner may be transferred to a third party without unitholder consent.

Our General Partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of our unitholders. Furthermore, there is no restriction in our partnership agreement on LBP's ability, as the ultimate owner of our General Partner, to transfer its ownership interest in our General Partner to a third party. The new owner of our General Partner would then be in a position to replace the Board of Directors and officers with its own choices and to control the decisions made and actions taken by the Board of Directors and officers.

A change of control would constitute an event of default under our Indenture, dated as of June 16, 2004 ("the Indenture"), relating to our Senior Notes, our U.S. revolving credit facility and our Canadian revolving credit facility. An event of default under the Indenture relating to our Senior Notes could require us to make an offer to purchase all of our Senior Notes then outstanding at a purchase price equal to 101% of the aggregate principal amount, plus accrued and unpaid interest, if any, to the date of purchase. During the continuance of an event of default under our U.S. revolving credit facility, the administrative agent may (and upon written instructions from lenders providing a majority of the loan commitments or the outstanding loan amount shall), terminate any outstanding commitments of the lenders to extend credit to us under our U.S. revolving credit facility and/or declare all amounts payable by us under our revolving credit facility immediately due and payable. An event of default under our Canadian revolving credit facility would also permit the Canadian administrative agent to declare all amounts payable by us under our Canadian revolving credit facility immediately due and payable.

We may issue additional units without your approval, which would dilute your ownership interests.

During the subordination period, our General Partner may cause us to issue up to 5,232,500 additional common units without unitholder approval. Our General Partner may also cause us to issue an unlimited number of additional common units or other partnership securities of equal rank with the common units, without unitholder approval, in a number of circumstances such as:

- the issuance of common units in connection with acquisitions or capital improvements that our General Partner determines would increase the amount of cash flow from operations per unit on a pro forma or estimated pro forma basis;
- the conversion of subordinated units into common units;
- the conversion of units of equal rank with the common units into common units under some circumstances;
- the conversion of the general partner interest and the incentive distribution rights into common units as a result of the withdrawal of our General Partner;
- issuances of common units pursuant to employee benefit plans; or
- issuances of common units to repay certain indebtedness.

Upon the expiration of the subordination period, we may issue an unlimited number of common units or other partnership securities without the approval of our unitholders. Our partnership agreement does not give our unitholders the right to approve our issuance of partnership securities ranking junior to the common units at any time.

The issuance of additional common units or other partnership securities of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Our General Partner may cause us to borrow funds in order to make cash distributions, even if the purpose or effect of the borrowing benefits the general partner or its affiliates.

In some instances, our General Partner may cause us to borrow funds from affiliates of LBP or from third parties to make cash distributions. These borrowings are permitted even if the purpose and effect of the borrowing is to enable us to make a distribution on the subordinated units, to make incentive distributions or to hasten the expiration of the subordination period.

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The owner of our General Partner has a substantial amount of debt. A default under such debt could result in a change of control of our General Partner, which would be an event of default under the instruments governing our long-term indebtedness.

LBP, the owner of our General Partner, financed its purchase of our General Partner through a combination of equity capital and the proceeds from a senior secured credit and guaranty agreement. LBP's existing credit and guaranty agreement is secured by pledges of substantially all of its assets, including the interest in our General Partner. LBP's indebtedness under its credit and guaranty agreement is rated B- by Standard & Poor's Rating Services ("S&P") and B1 by Moody's Investor Service, Inc. ("Moody's"). If LBP were to default on its obligations under its credit and guaranty agreement, the lenders could exercise their rights under these pledges, which could result in a change of control of our General Partner and a change of control of us. A change of control would constitute an event of default under our Indenture, our U.S. revolving credit facility and our Canadian revolving credit facility. An event of default under the Indenture could require us to make an offer to purchase all of our Senior Notes then outstanding at a purchase price equal to 101% of the aggregate principal amount, plus accrued and unpaid interest, if any, to the date of purchase. During the continuance of an event of default under our U.S. revolving credit facility, the administrative agent may (and upon written instructions from lenders providing a majority of the loan commitments or the outstanding loan amount shall), terminate any outstanding commitments of the lenders to extend credit to us under our U.S. revolving credit facility and/or declare all amounts payable by us under our revolving credit facility immediately due and payable. An event of default under our Canadian revolving credit facility would also permit the Canadian administrative agent to declare all amounts payable by us under our Canadian revolving credit facility immediately due and payable.

Our General Partner has a limited right to buy out minority unitholders if it owns more than 80% of the common units, which may require you to sell your common units against your will and at an undesirable time or price.

If at any time our General Partner and its affiliates own more than 80% of the common units, our General Partner will have the right, but not the obligation, to acquire all, but not less than all, of the remaining common units held by unaffiliated unitholders. As a result, you may be required to sell your common units against your will and at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your common units.

If our General Partner exercises its buy out right, the common units will be purchased at the greater of:

- the most recent 20-day average trading price ending on the date three days prior to the date the notice of purchase is mailed; or

- the highest price paid by our General Partner or its affiliates to acquire common units during the prior 90 days.

Our General Partner can assign its limited call right to an affiliate or to us.

Your liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law, and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. You could be liable for our obligations as if you were a general partner if:

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state's partnership statute; or

- your right to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

Unitholders may have liability to repay distributions.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 and 17-804 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to you if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Assignees who become substituted limited partners are liable for the obligations of the assignor to make contributions to the partnership that are known to the assignee at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the partnership agreement. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Tax Risks

The IRS could treat us as a corporation for tax purposes, which would substantially reduce any cash available for distribution to our unitholders.

The anticipated after-tax benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter that affects us.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rates, currently at a maximum rate of 35%, and would likely pay state income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gain, loss, or deduction would flow through to our unitholders. Because a tax would be imposed on us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders and therefore would likely result in a substantial reduction in the value of our common units. Moreover, treating us as a corporation would materially and adversely affect our ability to make payments on our debt securities.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon us as an entity, the cash available for distribution would be reduced. Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, then the minimum quarterly distribution amount and the target distribution amount will be adjusted to reflect the impact of that law on us.

A successful IRS contest of the federal income tax positions we take may adversely impact the market for our common units, and the costs of any contest will reduce cash available for distribution to our unitholders and our General Partner.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter that affects us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may disagree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will result in a reduction in cash available for distribution to our unitholders and our General Partner and thus will be borne indirectly by our unitholders and our General Partner.

Unitholders may be required to pay taxes on their share of our income from us even if they do not receive any cash distributions from us.

Unitholders will be required to pay any federal income taxes and, in some cases, state, local and foreign income taxes on their share of our taxable income, whether or not they receive cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the tax liability that results from the taxation of their share of our taxable income.

Tax gain or loss on disposition of our common units could be different than expected.

A unitholder who sells common units will recognize a gain or loss equal to the difference between the amount realized and the adjusted tax basis in those common units. Prior distributions to a unitholder in excess of the total net taxable income allocated to that unitholder, which decreased the tax basis in that unitholder's common unit, will, in effect, become taxable income to that unitholder if the common unit is sold at a price greater than that unitholder's tax basis in that common unit, even if the price is less than the original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to that unitholder.

Tax-exempt entities, regulated investment companies and foreign persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, including employee benefit plans and individual retirement accounts (known as IRAs), regulated investment companies (known as mutual funds) and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to such a unitholder. Recent legislation generally treats net income derived from the ownership of publicly traded partnerships as qualifying income to a regulated investment company. However, this legislation is only effective for taxable years beginning after October 22, 2004, the date of enactment. For taxable years beginning prior to the date of enactment, very little of our income will be qualifying income to a regulated investment company. Distributions to non-U.S. persons will be reduced by withholding taxes imposed at the highest effective tax rate applicable to individuals, and non-U.S. persons will be required to file United States federal income tax returns and pay tax on their share of our taxable income.

We treat each purchaser of our common units as having the same tax benefits without regard to the common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units, we will adopt depreciation and amortization positions that may not conform with all aspects of existing Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain on the sale of common units and could have a negative impact on the value of our common units or result in audits of and adjustments to our unitholders' tax returns.

Unitholders may be subject to state and local taxes and return filing requirements.

In addition to federal income taxes, unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property now or in the future, even if our unitholders do not reside in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, unitholders may be subject to penalties for failure to comply with those requirements. We own assets and do business in California, Montana, Wyoming, Colorado, Utah and Alberta, Canada. Of these states, only Wyoming does not currently impose a personal income tax. It is the responsibility of each unitholder to file all United States federal, state and local tax returns that may be required of such unitholder. Under certain circumstances, unitholders may be subject to foreign taxes and be required to file foreign tax returns.

ITEM 3. Legal Proceedings

We are involved in various regulatory disputes, litigation and claims arising out of our operations in the normal course of business. However, we are not currently a party to any legal or regulatory proceedings, the resolution of which we could expect to have a material adverse effect on our business, consolidated financial condition or results of operations.

ITEM 4. Submission of Matters to a Vote of Security Holders

There were no matters submitted to a vote of our unitholders during the fourth quarter of 2004.

Part II

ITEM 5. Market Price of and Distributions on the Registrant's Common Equity and Related Unitholder Matters

Our common units are listed on the New York Stock Exchange under the symbol "PPX." At the close of business on December 31, 2004, we had 127 holders of record of our common units, representing approximately 20,000 beneficial owners. The high and low sales price ranges per common unit, as reported on the New York Stock Exchange, and the amount of distributions declared by quarter for the years ended December 31, 2004 and 2003 are as follows:

	Price Range		Cash Distribution Per Limited Partner Unit(1)	Payment Date
	High	Low		
Year ended December 31, 2003				
First Quarter 2003	$ 21.47	$ 18.70	$ 0.4625	May 15, 2003
Second Quarter 2003	25.95	20.77	0.4625	August 14, 2003
Third Quarter 2003	28.30	23.60	0.4875	November 14, 2003
Fourth Quarter 2003	29.45	25.32	0.4875	February 13, 2004
Year ended December 31, 2004				
First Quarter 2004	$ 30.39	$ 27.10	$ 0.4875	May 14, 2004
Second Quarter 2004	28.55	21.96	0.4875	August 13, 2004
Third Quarter 2004	28.64	25.89	0.4875	November 12, 2004
Fourth Quarter 2004	29.47	26.48	0.5000	February 14, 2005

(1) Distributions declared associated with each respective quarter.

For equity compensation plan information, see "Item 12 Security Ownership of Beneficial Owners and Management."

We are party to credit agreements and an indenture governing our Senior Notes which contain certain financial covenants that may restrict our ability to make distributions to our unitholders. For a discussion regarding our credit agreements and Senior Notes, see "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations Credit Facilities and Long-term Debt."

Distributions of Available Cash

General. Within 45 days after the end of each quarter, we will distribute all of our available cash, if any, to unitholders of record on the applicable record date.

Definition of Available Cash. Available cash generally means, for each fiscal quarter:

- all cash on hand at the end of the quarter; less
- the amount of cash reserves that our General Partner determines in its reasonable discretion is necessary or appropriate to:
  - provide for the proper conduct of our business;
  - comply with applicable law, any of our debt instruments or other agreements; and
  - provide funds for distributions to our unitholders and to our General Partner for any one or more of the next four quarters; plus

all cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter. Working capital borrowings are generally borrowings that are made under our credit facilities and in all cases are used solely for working capital purposes or to pay distributions to partners.

Intent to Distribute Minimum Quarterly Distribution. We intend to distribute to holders of common units and subordinated units on a quarterly basis at least a minimum quarterly distribution of $0.4625 per unit per quarter, or $1.85 per unit per year, to the extent we have sufficient cash from our operations after establishment of cash reserves and payment of fees and expenses, including payments to our General Partner. However, there is no guarantee that we will pay the minimum quarterly distribution on the common units in any quarter and we are prohibited from making any distribution to unitholders if it would cause an event of default, or if an event of default is existing, under our U.S. revolving credit facility or pursuant to the indenture for our Senior Notes.

Operating Surplus, Capital Surplus and Adjusted Operating Surplus

General. All cash distributed to unitholders will be characterized as either operating surplus or capital surplus. We distribute available cash from operating surplus differently than available cash from capital surplus.

Definition of Operating Surplus. For any period, operating surplus generally means:

- our cash balance on July 26, 2002, the closing date of our initial public offering; plus
- $15.0 million (as described below); plus
- all of our cash receipts since the closing of our initial public offering, excluding cash from borrowings that are not working capital borrowings, sales of equity and debt securities and sales or other dispositions of assets outside the ordinary course of business; plus
- working capital borrowings made after the end of a quarter but before the date of determination of operating surplus for that quarter; less
- all of our operating expenses since the closing of our initial public offering, including the repayment of working capital borrowings, but not the repayment of other borrowings, and including maintenance capital expenditures; less
- the amount of cash reserves that our General Partner deems necessary or advisable to provide funds for future operating expenditures.

Definition of Adjusted Operating Surplus. Adjusted operating surplus is intended to reflect the cash generated from operations during a particular period and therefore excludes net increases in working capital borrowings and net drawdowns of reserves of cash generated in prior periods.

Adjusted operating surplus for any period generally means:

- operating surplus generated with respect to that period; less
- any net increase in working capital borrowings with respect to that period; less
- any net reduction in cash reserves for operating expenditures with respect to that period not relating to an operating expenditure made with respect to that period; plus
- any net decrease in working capital borrowings with respect to that period; plus
- any net increase in cash reserves for operating expenditures with respect to that period required by any debt instrument for the repayment of principal, interest or premium.

Definition of Capital Surplus. Capital surplus will generally be generated only by:

- borrowings other than working capital borrowings;
- sales of debt and equity securities; and

sales or other dispositions of assets for cash, other than inventory, accounts receivable and other current assets sold in the ordinary course of business or as part of normal retirements or replacements of assets.

Characterizations of Cash Distributions. We will treat all available cash distributed as coming from operating surplus until the sum of all available cash distributed since we began operations equals the operating surplus as of the most recent date of determination of available cash. We will treat any amount distributed in excess of operating surplus, regardless of its source, as capital surplus. As reflected above, operating surplus includes $15.0 million in addition to our cash balance on the closing date of our initial public offering, cash receipts from our operations and cash from working capital borrowings. This amount does not reflect actual cash on hand that is available for distribution to our unitholders. Rather this amount permits us, if we choose, to make limited distributions of cash from non-operating sources, such as asset sales, issuances of securities and long-term borrowings, which would otherwise be considered distributions of capital surplus. Any distributions of capital surplus would trigger certain adjustment provisions in our partnership agreement. We do not anticipate making any distributions from capital surplus.

Subordination Period

General. During the subordination period, the common units are entitled to receive distributions of available cash from operating surplus in an amount equal to the minimum quarterly distribution of $0.4625 per unit, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, to the extent we have sufficient cash from our operations after payment of fees and expenses, including payments to our General Partner and establishment of cash reserves, before any distributions of available cash from operating surplus may be made on the subordinated units. The purpose of the subordinated units is to increase the likelihood that during the subordination period there will be available cash to be distributed on the common units.

Definition of Subordination Period. The subordination period will generally expire on the first day of any quarter beginning after June 30, 2007, that each of the following tests are met:

- distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equaled or exceeded the minimum quarterly distribution for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date;

- the adjusted operating surplus generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum of the minimum quarterly distributions on all of the outstanding common units and subordinated units during those periods on a fully diluted basis plus the related distribution on the 2% general partner interest during those periods; and

- there are no arrearages in payment of the minimum quarterly distribution on the common units.

Early Conversion of Subordination Units. Prior to the end of the subordination period, 50% of the subordinated units, or up to 5,232,500 subordinated units, may convert into common units on a one-for-one basis immediately after the distribution of available cash to partners in respect of any quarter ending on or after:

- June 30, 2005, with respect to 25% of the subordinated units; and

- June 30, 2006, with respect to 25% of the subordinated units.

The early conversions will occur if, at the end of the applicable quarter, each of the following three tests are met:

- distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equaled or exceeded the minimum quarterly distribution for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date;

- the adjusted operating surplus generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum of the minimum quarterly distributions on all of the outstanding common units and subordinated units during those periods on a fully diluted basis plus the related distribution on the 2% general partner interest during those periods; and

- there are no arrearages in payment of the minimum quarterly distribution on the common units.

However, the second early conversion of the subordinated units may not occur until at least one year following the first early conversion of the subordinated units.

Based on our results to date and our forecasted results through June 30, 2005, we expect that 25% of the subordinated units will convert to common units immediately after the distribution of available cash in respect of the quarter ending June 30, 2005.

Effect of Expiration of the Subordination Period. Upon expiration of the subordination period, each outstanding subordinated unit will automatically convert into one common unit and will then participate, pro rata, with the other common units in any distributions of available cash. In addition, if the unitholders remove our General Partner other than for cause and units held by our General Partner and its affiliates are not voted in favor of that removal:

- the subordination period will end and all outstanding subordinated units will immediately convert into one common unit;

- any existing arrearages in payment of the minimum quarterly distribution on the common units will be extinguished; and

- our General Partner will have the right to convert its general partner interest and its incentive distribution rights into common units or to receive cash in exchange for those interests.

Distributions of Available Cash from Operating Surplus During the Subordination Period

We will make distributions of available cash from operating surplus for any quarter during the subordination period in the following manner:

- *First*, 98% to the common unitholders, pro rata, and 2% to our General Partner, until we have distributed for each outstanding common unit an amount equal to the minimum quarterly distribution for that quarter;

- *Second*, 98% to the common unitholders, pro rata, and 2% to our General Partner, until we have distributed for each outstanding common unit an amount equal to any arrearages in payment of the minimum quarterly distribution on the common units for any prior quarters during the subordination period;

- *Third*, 98% to the subordinated unitholders, pro rata, and 2% to our General Partner, until we have distributed for each subordinated unit an amount equal to the minimum quarterly distribution for that quarter; and

- *Thereafter*, in the manner described in " Incentive Distribution Rights" below.

Distributions of Available Cash from Operating Surplus After the Subordination Period

We will make distributions of available cash from operating surplus for any quarter after the subordination period in the following manner:

First, 98% to all unitholders, pro rata, and 2% to our General Partner, until we have distributed for each outstanding unit an amount equal to the minimum quarterly distribution for that quarter; and

Thereafter, in the manner described in " Incentive Distribution Rights" below.

Incentive Distribution Rights

Incentive distribution rights represent the right to receive an increasing percentage of quarterly distributions of available cash from operating surplus, up to 48%, after the minimum quarterly distribution and the target distribution levels have been achieved. Our General Partner currently holds the incentive distribution rights, but may transfer these rights separately from its general partner interest, subject to restrictions in the partnership agreement.

If for any quarter:

we have distributed available cash from operating surplus on each common unit and subordinated unit in an amount equal to the minimum quarterly distribution; and

we have distributed available cash from operating surplus on each outstanding common unit in an amount necessary to eliminate any cumulative arrearages in payment of the minimum quarterly distribution;

then, we will distribute any additional available cash from operating surplus for that quarter among the unitholders, our General Partner and the holders of the incentive distribution rights (if other than our General Partner) in the following manner:

First, 98% to all unitholders, pro rata, and 2% to our General Partner, until each unitholder has received a total of $0.5125 per unit for that quarter (the "first target distribution");

Second, 85% to all unitholders, pro rata, 13% to the holders of the incentive distribution rights, pro rata, and 2% to our General Partner, until each unitholder has received a total of $0.5875 per unit for that quarter (the "second target distribution");

Third, 75% to all unitholders, pro rata, 23% to the holders of the incentive distribution rights, pro rata, and 2% to our General Partner, until each unitholder has received a total of $0.7000 per unit for that quarter (the "third target distribution"); and

Thereafter, 50% to all unitholders, pro rata, 48% to the holders of the incentive distribution rights, pro rata, and 2% to our General Partner.

In each case, the amount of the target distribution set forth above is exclusive of any distributions to common unitholders to eliminate any cumulative arrearages in payment of the minimum quarterly distribution.

Percentage Allocations of Available Cash from Operating Surplus

The following table illustrates the percentage allocations of the additional available cash from operating surplus between the unitholders and our General Partner up to the various target distribution levels. The amounts set forth under "Marginal Percentage Interest in Distributions" are the percentage interests of our General Partner and the unitholders in any available cash from operating surplus we distribute up to and including the corresponding amount in the column "Total Quarterly Distribution Target Amount," until available cash we distribute reaches the next target distribution level, if any. The percentage interests shown for the unitholders and our General Partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests shown for our General Partner include its 2% general partner interest and assume that our General Partner has not transferred the incentive distribution rights.

		Marginal Percentage Interest in Distributions	
	Total Quarterly Distribution Target Amount	Unitholders	General Partner
Minimum Quarterly Distribution	$0.4625	98%	2%
First Target Distribution	up to $0.5125	98%	2%
Second Target Distribution	above $0.5125 up to $0.5875	85%	15%
Third Target Distribution	above $0.5875 up to $0.7000	75%	25%
Thereafter	above $0.7000	50%	50%

ITEM 6. Selected Financial and Operating Data

General

The following table shows selected financial and operating data of Pacific Energy Partners, L.P., the successor to Pacific Energy and subsidiaries (Predecessor) (as defined below) for the periods and as of the dates indicated. The data consists of the consolidated financial and operating data of the Partnership and its 100% ownership interest in Pacific Energy Group LLC ("PEG") and PEG Canada GP LLC. PEG's subsidiaries consist of (i) Pacific Pipeline System LLC ("PPS"), owner of Line 2000 and the Line 63 system, (ii) Pacific Terminals LLC ("PT"), owner of the Pacific Terminals storage and distribution system acquired on July 31, 2003, (iii) Pacific Marketing and Transportation LLC ("PMT"), owner of the PMT gathering and blending system acquired on July 1, 2001, (iv) Rocky Mountain Pipeline System LLC ("RMPS"), owner of the Western Corridor and the Salt Lake City Core systems acquired on March 1, 2002, and (v) Ranch Pipeline LLC ("RPL"), the owner of a 22.22% partnership interest in Frontier.

PEG Canada GP LLC is the general partner of PEG Canada, L.P. ("PEG Canada"), the holding company of our Canadian subsidiaries. We own 100% of the limited partner interests in PEG Canada, whose 100% owned subsidiaries consist of (i) Rangeland Pipeline Company ("RPC"), which owns 100% of Aurora Pipeline Company Ltd. ("APC") and a partnership interest in Rangeland Pipeline Partnership ("RPP"), (ii) Rangeland Northern Pipeline Company ("RNPC"), which owns the remaining partnership interest in RPP, and (iii) Rangeland Marketing Company ("RMC"). RPP owns all of the assets that make up the Rangeland pipeline system except the Aurora pipeline, which is owned by APC.

The Partnership also owns 100% of Pacific Energy Finance Corporation, which was organized for the sole purpose of co-issuing the Senior Notes in June 2004.

Prior to July 26, 2002, the financial and operating data for PPS, PMT, RMPS and RPL, are presented on a combined basis and constitute the Predecessor. The financial data for 2000 and 2001 are derived from the audited combined financial statements of Pacific Energy (Predecessor). The PMT gathering and blending system was purchased on July 1, 2001 and is included in the financial and operating data after that date. The Western Corridor and the Salt Lake City Core systems were purchased on March 1, 2002. Accordingly, for 2000 and 2001 our Rocky Mountain operations included only AREPI pipeline, which was integrated into the Salt Lake City Core system on January 1, 2004, and Frontier pipeline (under the equity method) and do not include the Western Corridor or the Salt Lake City Core systems.

The Pacific Terminals storage and distribution system was purchased on July 31, 2003 and is included in the financial and operating data from that date. The Rangeland system and the MAPL pipeline were purchased on May 11, 2004 and June 30, 2004, respectively, and both are included in the financial and operating data from those dates.

Sustaining capital expenditures are capital expenditures made to replace partially or fully depreciated assets in order to maintain the existing operating capacity or efficiency of our assets and extend their useful lives. Transitional capital expenditures are made to integrate acquired assets into our existing operations. Expansion capital expenditures are made to expand or increase the efficiency of the existing operating capacity of our assets, whether through construction or acquisition. We treat repair and maintenance expenditures that do not extend the useful life of existing assets as operating expenses and expense them as incurred.

Certain prior year balances in the accompanying condensed consolidated financial statements have been reclassified to conform to current year presentation.

Non-GAAP Financial Measures

EBITDA is used as a supplemental financial measure by management and by external users of our financial statements, such as investors, commercial banks, research analysts and rating agencies, to assess: (i) the financial performance of our assets without regard to financing methods, capital structures or historical cost basis; (ii) the ability of our assets to generate cash sufficient to pay interest cost and support our indebtedness; (iii) our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing and capital structure; and (iv) the viability of projects and the overall rates of return on alternative investment opportunities. EBITDA is not a generally accepted accounting principle financial measure and should not be considered as an alternative to net income, income before taxes, cash flows from operations, or any other measure of financial performance presented in accordance with GAAP. EBITDA is not intended to represent cash flow. Our EBITDA may not be comparable to EBITDA or similarly titled measures of other companies.

Several adjustments to net income are required to calculate EBITDA. These adjustments include: (i) the addition of interest expense; (ii) the addition of depreciation and amortization expense; (ii) the addition of write-off of deferred financing cost and interest rate swap termination expense; (iii) the addition of write-down of idle property; (iv) the addition of non-cash employee compensation under the long-term incentive plan, which is included in general and administrative expense; and (v) the addition of income tax expense. The Partnership is not a taxable entity in the U.S., however, its Canadian subsidiaries are taxable entities in Canada.

Distributable cash flow is presented in the selected financial data for 2004 and 2003. On July 26, 2002, we completed our initial public offering of common units. Accordingly, distributable cash flow is not presented for 2002, 2001 and 2000. We believe that investors benefit from having access to the same financial measures being utilized by management. Distributable cash flow is a significant financial measure used by our management to compare cash flows generated by the partnership to the cash distributions we make to our partners. This is an important financial measure for our limited partners since it is an indicator of our success in providing a cash return on their investment. Specifically, this financial measure tells investors whether or not the partnership is generating cash flows at a level that can sustain or support an increase in our quarterly cash distributions paid to partners. Lastly, distributable cash flow is the quantitative standard used throughout the investment community with respect to publicly-traded partnerships. However, distributable cash flow is not a generally accepted accounting principle financial measure and should not be considered as an alternative to net income, cash flow from operations, or any other measure of financial performance presented in accordance with accounting principles generally accepted in the United States. In addition, our distributable cash flow may not be comparable to distributable cash flow or similarly titled measures of other companies.

Several adjustments to net income are required to calculate distributable cash flow. These adjustments include: (i) the addition of depreciation and amortization expense; (ii) the addition of amortization of debt issue costs and accretion of discount on debt instruments, which are included in interest expense; (iii) the addition of non-cash employee compensation under the long-term incentive plan, which is included in general and administrative expense; (iv) the addition of the write-off of deferred financing cost associated with repayment of our term loan in 2004; (v) the addition of the write-down of idle PT property; (vi) the addition of deferred tax expense or the subtraction of deferred income tax benefit; and (vii) the subtraction of sustaining capital expenditures.

The following table should be read together with, and is qualified in its entirety by reference to, the consolidated financial statements and the accompanying notes included elsewhere in this Annual Report on Form 10-K. The table should also be read together with "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Years Ended December 31,				
	2004	**2003**	**2002**	**2001**	**2000**
	(in thousands, except per unit amounts)				
Consolidated Statements of Income:					
Revenue:					
Pipeline transportation(1)	$ 108,395	$ 101,811	$ 103,090	$ 66,331	$ 71,419
Storage and distribution(2)	37,577	12,711			
Pipeline buy/sell transportation(3)	18,640				
Crude oil sales, net of purchases(4)	16,787	21,293	21,104	7,236	
Net revenue before expenses	181,399	135,815	124,194	73,567	71,419
Expenses:					
Operating	84,729	60,649	55,184	34,032	26,988
Transition costs	557	397	2,633	220	
General and administrative	15,400	13,705	7,515	2,787	2,672
Rate case litigation expense(5)				1,853	
Depreciation and amortization	24,173	18,865	15,919	11,368	11,873
Total expenses	124,859	93,616	81,251	50,260	41,533
Share of net income (loss) of Frontier:					
Income before rate case and litigation expense	1,328	1,459	1,904	1,569	1,738
Rate case and litigation expense		(1,621)	(557)		
Share of net income (loss) of Frontier(6)	1,328	(162)	1,347	1,569	1,738
Write-down of idle property(7)	(800)				
Operating income	57,068	42,037	44,290	24,876	31,624
Other income	1,032	479	918	787	831
Write-off of deferred financing cost and interest rate swap termination expense	(2,901)				
Interest expense	(19,209)	(17,487)	(11,634)	(10,056)	(18,115)
Income before income taxes	35,990	25,029	33,574	15,607	14,340
Income tax (expense) benefit:					
Current	(326)				
Deferred	65				
	(261)				
Net income	$ 35,729	$ 25,029	$ 33,574	$ 15,607	$ 14,340
Basic net income per limited partner unit(8)	$ 1.23	$ 1.10	$ 0.55	$	$
Diluted net income per limited partner unit(8)	$ 1.23	$ 1.09	$ 0.55	$	$
Weighted average limited partner units outstanding(8):					
Basic	28,406	22,328	20,930		
Diluted	28,488	22,540	20,930		
Other Financial Data:					
EBITDA(9)	$ 83,930	$ 63,580	$ 61,199	$ 37,031	$ 44,328
Distributable Cash Flow(10)	63,399	44,972			
Net cash provided by operating activities	57,226	42,754	45,793	26,406	26,319
Net cash used in investing activities	(155,952)	(180,332)	(101,311)	(37,203)	(3,487)
Net cash provided by (used in) financing activities	112,410	123,404	69,880	8,044	(17,571)
Capital expenditures:					
Sustaining	$ 1,953	$ 2,149	$ 2,725	$ 3,381	$ 1,662

	Years Ended December 31,				
Transition	1,874	351	2,039		
Expansion	12,693	8,392	878	2,433	1,825
Total capital expenditures	$ 16,520	$ 10,892	$ 5,642	$ 5,814	$ 3,487

	Years Ended December 31,				
	2004	2003	2002	2001	2000
	(in thousands)				
Balance Sheet Data (at period end):					
Property and equipment, net	$ 718,624	$ 567,954	$ 404,842	$ 309,675	$ 340,889
Total assets	869,905	650,203	487,038	372,179	366,011
Total debt, including current portion	357,163	298,000	225,000	181,333	240,000
Net partners' capital (net parent investment)	422,466	295,067	215,267	157,361	117,528
Limited partner units outstanding(8)	29,624	24,907	20,930		
Operating Data:					
West Coast Business Unit:					
Pipeline throughput (mbpd)(11)	141.2	151.0	162.8	158.0	166.3
Rocky Mountain Business Unit throughput (mbpd)(11):					
Rangeland system:					
Sundre North	21.0				
Sundre South	48.1				
Western Corridor system	20.2	16.7	15.0		
Salt Lake City Core system(12)	115.1	107.5	115.6	41.1	39.4
Frontier pipeline(13)	47.4	41.7	44.4	40.5	37.4

(1) Includes our ownership of the Western Corridor and Salt Lake City Core systems from March 1, 2002.

(2) Includes our ownership of the Pacific Terminals storage and distribution system from July 31, 2003.

(3) Includes our ownership of the Rangeland system, which we acquired on May 11, 2004 and June 30, 2004.

(4) The above amounts are net of purchases of $402,283, $358,454, $316,283 and $160,085 for 2004, 2003, 2002 and 2001, respectively. The results for 2001 include six months of gathering and blending operations from PMT's acquisition on July 1, 2001.

(5) Provision for settlement expenses related to the AREPI pipeline rate case litigation. The AREPI pipeline was integrated into the Salt Lake City Core system on January 1, 2004.

(6) 2000 includes 12.5% of the net income of Frontier Pipeline Company. On December 17, 2001, Pacific Energy (Predecessor) acquired an additional 9.72% partnership interest in Frontier Pipeline Company. Therefore, 2001 includes 12.5% of the net income of Frontier Pipeline Company for the period January 1, 2001 through December 16, 2001 and 22.22% for the balance of the year. The data for 2002 and subsequent years include 22.22% of the net income of Frontier Pipeline Company.

(7) This amount represents a write-down to fair market value of idle PT property that is expected to be sold.

(8) On July 26, 2002, the Partnership completed its initial public offering of common units. Net income per limited partner unit is based on net income of $11,817 for the period from July 26, 2002 to December 31, 2002. Weighted average limited partner units outstanding for 2002 was calculated for the period from July 26, 2002 to December 31, 2002.

(9)

A reconciliation from reported net income to EBITDA is as follows:

	Years Ended December 31,				
	2004	2003	2002	2001	2000
	(in thousands)				
Net income	$ 35,729	$ 25,029	$ 33,574	$ 15,607	$ 14,340
Interest expense	19,209	17,487	11,634	10,056	18,115
Depreciation and amortization	24,173	18,865	15,919	11,368	11,873
Write-off of deferred financing cost and interest rate swap termination expense	2,901				
Write-down of idle property	800				
Non-cash portion of our long-term incentive plan expense	857	2,199	72		
Income tax expense	261				
EBITDA	$ 83,930	$ 63,580	$ 61,199	$ 37,031	$ 44,328

Interest income of $209, $156, $385, $320 and $474 for each of the five years ended December 31, 2004, respectively, is not deducted in determining EBITDA.

(10)

On July 26, 2002, we completed our initial public offering of common units. Accordingly, distributable cash flow is not presented for 2002, 2001, and 2000. A reconciliation from reported net income to distributable cash flow for the years ended December 31, 2004 and 2003 is as follows:

	Year Ended December 31,	
	2004	2003
	(in thousands)	
Net income	$ 35,729	$ 25,029
Depreciation and amortization	24,173	18,865
Amortization of debt issue costs and accretion of discount on long-term debt	1,537	1,028
Non-cash employee compensation under long-term incentive plan	857	2,199
Write-off of deferred financing cost	2,321	
Write-down of idle property	800	
Deferred income tax benefit	(65)	
Sustaining capital expenditures	(1,953)	(2,149)
Distributable cash flow	$ 63,399	$ 44,972

(11)

Throughput is the total number of barrels per day transported on a pipeline system. We recognize throughput at the time a barrel of crude oil is delivered to its ultimate delivery point.

(12)
AREPI pipeline was integrated into the Salt Lake City Core system on January 1, 2004.

(13)
This figure represents 100% of the throughput on Frontier pipeline.

ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion of the financial condition and results of operations of Pacific Energy Partners, L.P., the successor to Pacific Energy (Predecessor) (as defined below), should be read together with the consolidated financial statements and the notes thereto set forth elsewhere in this report. The discussion set forth in this section pertains to our consolidated financial position, statements of income, statements of cash flows and statement of partners' capital.

The Partnership owns a 100% interest in Pacific Energy Group LLC ("PEG"), whose subsidiaries consist of (i) Pacific Pipeline System LLC ("PPS"), owner of Line 2000 and the Line 63 system, (ii) Pacific Terminals LLC ("PT"), owner of the Pacific Terminals storage and distribution system, (iii) Pacific Marketing and Transportation LLC ("PMT"), owner of the PMT gathering and blending system, (iv) Rocky Mountain Pipeline System LLC ("RMPS"), owner of the Western Corridor and Salt Lake City Core systems, and (v) Ranch Pipeline LLC ("RPL"), the owner of a 22.22% partnership interest in Frontier Pipeline Company ("Frontier").

The Partnership also owns a 100% interest in PEG Canada GP LLC, the general partner of PEG Canada, L.P. ("PEG Canada"), the holding company for our Canadian subsidiaries. We own 100% of the limited partner interests in PEG Canada, whose 100% owned subsidiaries consist of (i) Rangeland Pipeline Company ("RPC"), which owns 100% of Aurora Pipeline Company Ltd. ("APC") and a partnership interest in Rangeland Pipeline Partnership ("RPP"), (ii) Rangeland Northern Pipeline Company ("RNPC"), which owns the remaining partnership interest in RPP, and (iii) Rangeland Marketing Company ("RMC"). RPP owns all of the assets that make up the Rangeland pipeline system except the Aurora pipeline, which is owned by APC.

We also own 100% of Pacific Energy Finance Corporation, co-issuer of our 7 1/8% Senior Notes due 2014 (the "Senior Notes").

For the periods prior to July 26, 2002, the date of our initial public offering, the financial data and results of operations for PPS, PMT, RMPS and RPL, are presented on a combined basis and constitute the Predecessor.

The financial data included herein reflects (i) the ownership and results of operations of the Western Corridor and Salt Lake City Core systems from March 1, 2002; (ii) the ownership and results of operations of the assets comprising the Pacific Terminals storage and distribution system for the period from July 31, 2003; (iii) the ownership and results of operations of the Rangeland system for the period from May 11, 2004; and (iv) the ownership of the MAPL pipeline for the period from June 30, 2004. Each of these acquisitions closed on the date indicated.

Overview

We are a publicly traded partnership engaged principally in the business of gathering, transporting, storing and distributing crude oil and related products in California and the Rocky Mountain region of the U.S. and in Alberta, Canada. We conduct our business through two regional business segments: the West Coast Business Unit and the Rocky Mountain Business Unit. We generate revenue primarily by charging tariff rates for transporting crude oil on our pipelines and by leasing storage capacity. We also buy, blend and sell crude oil, activities that are complementary to our pipeline transportation business.

We are managed by our general partner, Pacific Energy GP, LP, which is in turn managed by its general partner, Pacific Energy Management LLC. See "Recent Developments" below.

Our West Coast Business Unit consists of (i) Line 2000, (ii) the Line 63 system, (iii) the Pacific Terminals storage and distribution system and (iv) the PMT gathering and blending system. We transport crude oil produced in California's San Joaquin Valley and the California Outer Continental Shelf ("OCS") to refineries and terminal facilities in the Los Angeles Basin and in Bakersfield. In addition, we own and operate storage and distribution assets servicing the Los Angeles Basin. Our West Coast Business Unit also buys, blends and sells crude oil, in large measure as a means of generating additional volumes on our pipelines. We are developing a deepwater petroleum import terminal at Pier 400 and Terminal Island in the Port of Los Angeles ("POLA").

Our Rocky Mountain Business Unit consists of (i) certain undivided interest in the Western Corridor system, (ii) the Salt Lake City Core system, (iii) RPL's interest in Frontier pipeline Company, and (iv) beginning in May 2004, the Rangeland system. In June 2004, we acquired the Mid Alberta Pipeline (the "MAPL pipeline") and integrated it with Rangeland. We are transforming Rangeland from being primarily a gathering pipeline, serving conventional production areas in central and southern Alberta, into a main line transporting system with access in Edmonton, Alberta, to the growing synthetic oil production as well as the existing conventional oil production of Alberta. The combination of the Rangeland and MAPL assets with our existing Rocky Mountain Business Unit allows us to transport crude oil produced in Canada and the U.S. Rocky Mountain region to refineries in Montana, Wyoming, Colorado and Utah, either directly through our pipelines or indirectly through connections with third-party pipelines.

Cash distributions

Our principal business objective is to generate stable and increasing cash flows by being a leading provider of pipeline transportation and other midstream services to the North American energy industry. We seek to achieve our objective by executing the following strategies:

- Use our strategic position in our core market areas to maximize throughput on our pipelines and utilization of our storage facilities.

- Control our operating and capital costs while maintaining the safety and operational integrity of our assets.

- Pursue strategic and accretive acquisitions and new projects that enhance and expand our core business.

- Minimize our exposure to commodity price volatility.

Our ability to execute this acquisition and development strategy successfully is dependent on the price we pay for the acquisitions or the cost of development relative to the future cash flows the new assets generate.

Our cash distributions to unitholders may vary over time with the cash flow from our operating activities. Our operating cash flow is impacted by the revenue and cost variables described below. Our cash distributions may also vary over time with the level of sustaining capital expenditures. These expenditures are required to replace partially or fully depreciated assets in order to maintain the existing operating capacity or efficiency of our assets and extend their useful lives.

During the subordination period, the common units are entitled to receive distributions of available cash from operating surplus in an amount equal to the minimum quarterly distribution of $0.4625 per unit, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, to the extent we have sufficient cash from our operations after payment of fees and expenses, including payments to our General Partner and establishment of cash reserves, before any distributions of available cash from operating surplus may be made on the subordinated units. The existence of the subordinated units increases the likelihood that during the subordination period there will be available cash to distribute the minimum quarterly distribution to the holders of the common units. See "Item 5 Market Price of and Distributions on the Registrant's Common Equity and Related Unitholder Matters" regarding subordinated units and the subordination period.

Recent Developments

Sale of The Anschutz Corporation's Interest in the Partnership

On March 3, 2005, The Anschutz Corporation completed the sale of its 36.6% interest in us to LB Pacific, LP ("LBP"), an entity formed by Lehman Brothers Merchant Banking Group ("LBMB"). The acquisition by LBP (the "LB Acquisition") included the purchase of a 100% ownership interest in Pacific Energy GP, Inc. (predecessor of Pacific Energy GP, LP), which owned (i) a 2% general partner interest in us and the incentive distribution rights, and (ii) 10,465,000 subordinated units of the Partnership representing a 34.6% limited partner interest in us. Immediately prior to the closing of the LB Acquisition, Pacific Energy GP, Inc. was converted to Pacific Energy GP, LLC, a Delaware limited liability company; and immediately after the closing of the LB Acquisition, Pacific Energy GP, LLC was converted to Pacific Energy GP, LP, a Delaware limited partnership. The general partner of Pacific Energy GP, LP is Pacific Energy Management LLC, a Delaware limited liability company, which is 100% owned by LBP. Immediately following the closing of the LB Acquisition, our General Partner distributed the 10,465,000 subordinated units of the Partnership to LBP.

In connection with the conversion of our General Partner to a limited partnership, our General Partner ceased to have a board of directors, and is now managed by its general partner, Pacific Energy Management LLC, a Delaware limited liability company ("PEM"), which is 100% owned by LBP. PEM has a board of directors (the "Board of Directors" or "Board") that manages the business and affairs of PEM and, thus, indirectly manages the business and affairs of our General Partner and the Partnership. The Board of Directors is comprised of six of the directors who served on the Board of Directors of our General Partner prior to the LB Acquisition, together with four directors appointed by LBP. For further discussion of the Board of Directors, see "Item 10 Directors and Executive Officers". All of the officers and employees of our General Partner were transferred to fill the same positions with PEM, and the Board established the same committees as had been maintained by our General Partner prior to the LB Acquisition. PEM also adopted our General Partner's compensation structure and its employee benefits plans and policies.

Canadian Acquisitions

Rangeland System Acquisition. On May 11, 2004, we completed the acquisition of the Rangeland system from BP Canada Energy Company ("BP"). The Rangeland system is located in Alberta, Canada. The purchase price for the Rangeland system was Cdn$130.1 million plus approximately Cdn$32.2 million for linefill, working capital and transaction costs for an aggregate purchase price of US$118.1 million. The purchase was funded through a combination of proceeds from our March 2004 equity offering and a Cdn$45 million borrowing from a new Cdn$100 revolving credit facility in Canada.

MAPL Pipeline Acquisition. On June 30, 2004, we completed the acquisition of the MAPL pipeline, located in Alberta, Canada, from Imperial Oil. The purchase price for the MAPL pipeline was Cdn$31.5 million, of which Cdn$5.0 million is payable on June 30, 2007. In addition, we acquired linefill for Cdn$5.0 million. The aggregate purchase price, including assumed liabilities, linefill and transaction costs, was approximately US$27.0 million, most of which was funded from our Canadian credit facility.

Integration and Transition. The Rangeland system and the MAPL pipeline have each historically been operated on a proprietary basis. We have integrated the MAPL pipeline into the Rangeland system. We are making significant changes to the revenue-generating capability of these assets by combining and integrating fully all of our Canadian and U.S. Rocky Mountain pipeline assets under common management, by expanding the throughput capacity of the Rangeland system by establishing connections with other pipelines, and by constructing a pump station and receiving terminal in Edmonton, Alberta. This new pump station and receiving terminal will be able to access multiple sources of Canadian crude oil, which will allow us to participate in the projected increase in production of synthetic crude oil. The construction of the new connections on the Rangeland system and the new pump station and receiving terminal is expected to cost approximately Cdn$12 million, and is expected to be completed in the fourth quarter of 2005.

Pier 400

In February 2004, we completed an initial feasibility study for the development of a deepwater petroleum import terminal at Pier 400 and Terminal Island in the Port of Los Angeles ("POLA") to handle marine receipts of crude oil and refinery feedstocks. We are developing the Pier 400 terminal to participate in the marine import business, which is growing as a result of a decline in imports from Alaska and the local production decline. The Pacific Terminals storage and distribution assets also benefit by the increase in the marine import business.

We initiated the environmental review and permitting for the Pier 400 project in June 2004 and expect to have the permits necessary for construction to begin by early 2006. We entered into a project development agreement with two subsidiaries of Valero Energy Corporation ("Valero") that defines the facilities that we are to construct in the POLA. We and Valero have also signed a terminaling services agreement with a 30-year, 50,000 bpd volume commitment from Valero to support the terminal. These agreements are subject to the satisfaction of various conditions.

If the Pier 400 terminal receives the necessary governmental approvals and is successfully developed, a deepwater berth, high capacity transfer infrastructure and storage tanks will be constructed at Pier 400 and Terminal Island in the POLA and a pipeline distribution system will be constructed to connect the terminal's storage tanks to Valero's Wilmington refinery and to our customers' facilities in the Los Angeles Basin through our Pacific Terminals storage and distribution system. We would construct the transfer infrastructure, including a large diameter pipeline system for receiving bulk petroleum liquids from marine vessels, and the storage tanks.

Final construction of the Pier 400 project is subject to the completion of a land lease agreement with the POLA, receipt of environmental and other approval, securing additional customer commitments, updating engineering and project cost estimates, ongoing feasibility evaluation, and financing. A final decision to proceed is expected to be made in the fourth quarter of 2005. We expect construction of the Pier 400 terminal to be completed and placed in service in 2007.

We capitalized approximately $5.3 million on the Pier 400 project in 2003 and $5.2 million in 2004. These expenditures include $6.3 million for emission reduction credits, an asset that is re-saleable if the project does not proceed. We anticipate funding pre-construction costs through late-2005 from a portion of the proceeds from our March 2004 equity offering. Construction of the Pier 400 terminal is expected to be financed through a combination of debt and proceeds from the issuance of additional partnership units, including common units.

Salt Lake City Expansion Project

We also recently expanded our pipelines serving Salt Lake City by establishing a new delivery connection from Frontier pipeline to the Salt Lake City Core system at a cost of approximately $3.4 million. Existing pipelines into Salt Lake City were previously prorated, or limited by capacity, during the summer season. This connection increases delivery capacity to Salt Lake City refineries by approximately 7,000 bpd.

Equity and Debt Offerings

On March 30, 2004, we issued and sold 4,200,000 common units in an underwritten public offering at a price of $28.50 per common unit before underwriting fees and offering expenses. On April 12, 2004, the underwriters exercised a portion of the over-allotment option and purchased an additional 425,000 common units to cover over-allotments at a price of $28.50 per common unit before underwriting fees and offering expenses. Net proceeds received from the offering, including our General Partner's contribution of $2.7 million, totaled approximately $128.5 million after deducting underwriting fees and offering expenses. We used $86 million of the net proceeds to finance the acquisition of the Rangeland system and the balance of the net proceeds to repay borrowings outstanding under our U.S. revolving credit facility.

On June 16, 2004, we completed the sale of $250 million of Senior Notes due 2014 in a private offering to qualified institutional buyers in reliance on Rule 144A of the Securities Act of 1933, as amended (the "Securities Act") and to non-U.S. persons under regulation S of the Securities Act. The Senior Notes were issued at a discount of $4.4 million, resulting in an effective interest rate of 7.375%. Net proceeds from the issuance of the Notes were $240.9 million after deducting the $4.4 million discount and offering expenses of $4.7 million. The net proceeds were used principally to repay our $225 million term loan and to repay $16 million of indebtedness outstanding under our U.S. revolving credit facility.

On September 2, 2004, we filed a Registration Statement on Form S-4 to register the Senior Notes. On September 23, 2004, we commenced an exchange offer, which allowed the holders of the unregistered Senior Notes to exchange the Senior Notes for new notes with materially identical terms that had been registered under the Securities Act. The exchange offer expired on October 29, 2004, and all of the unregistered Senior Notes were exchanged for registered Senior Notes. The Senior Notes are not listed on any securities exchange.

In connection with the issuance of the Senior Notes, we entered into interest rate swap agreements with an aggregate notional principal amount of $80 million to receive interest at a fixed rate of $7^1/_8$% and to pay interest at an average variable rate of six month LIBOR plus 1.6681% (set in advance or in arrears depending on the swap transaction). The net impact on our interest expense of the notes offering, the related interest rate swap and the term loan repayment is that we expect our interest expense to remain largely unchanged.

Business Fundamentals

Pipeline Transportation

We generate pipeline transportation revenue by charging tariff rates for transporting crude oil on our common carrier pipelines. The fundamental items impacting our pipeline transportation revenue are the volume of crude oil, or throughput, we transport on our pipelines and our tariff rates. Throughput on our pipelines fluctuates based on the volume of crude oil available for transport on our pipelines, the demand for refined products, refinery downtime and the availability of alternate sources of crude oil for the refineries we serve.

Our shippers determine the amount of crude oil we transport on our pipelines, but we influence these volumes through the level and type of service we provide and the rates we charge. Our rates need to be competitive to transportation alternatives, which are mostly other pipelines.

The availability of crude oil for transportation on our pipelines is dependent in part on the amount of drilling and enhanced recovery activity in the production fields we serve in our West Coast operations and in parts of our Rocky Mountain operations. With the passage of time, production of crude oil in an individual well naturally declines, which can in the short-term be offset in whole or in part by additional drilling or the implementation of recovery enhancement measures. In the San Joaquin Valley and in the California OCS, total production is generally declining. In the third quarter of 2004, producers began the development of the Rocky Point field in the California OCS with the drilling of the first of eight planned wells. The first well began production at the end of the third quarter of 2004, thereby increasing the supply of crude oil available to be transported by us into the Los Angeles Basin. We anticipate that a significant portion of any incremental OCS production will be transported on our pipelines.

Shell Oil Company recently announced that it has entered into a definitive agreement to sell its Bakersfield refinery. Shell had previously intended to close the refinery. While we would benefit from a closure of the Shell refinery, we are also positioned to benefit from its sale to a third party and its continued operation through our delivery of additional volumes of crude oil to the refinery and from the deliveries of partially refined feedstocks from the refinery south to the Los Angeles Basin.

In the Rocky Mountains, our pipelines are connected to Canadian sources of crude oil, and in 2004 we completed the acquisitions of pipeline systems giving us greater access to significant supplies of Canadian crude oil, including synthetic crude oil, which we believe will replace any U.S. Rocky Mountain production decline and meet growing demand in the U.S. Rocky Mountain region.

The tariff rates we charge on Line 2000 and the Line 63 system are regulated by the California Public Utilities Commission (the "CPUC"). Tariffs on Line 2000 are established based on market considerations, subject to certain contractual limitations. Tariffs on Line 63, which are cost-of-service based tariffs, are based upon the costs to operate and maintain the pipeline, as well as charges for the depreciation of the capital investment in the pipeline and the authorized rate of return. The tariff rates charged on our U.S. Rocky Mountain pipelines are regulated by either the FERC or the Wyoming Public Service Commission, generally under a cost-of-service approach. In Canada, the Rangeland system is operated as a propriety pipeline system, not subject to rate regulation.

On May 1, 2004, we increased the tariff rates on Line 2000 by approximately 6%, based on a contractually agreed index of cost changes. This index is reviewed annually. Effective November 1, 2004, we increased the tariff rates on our Line 63 system by 9.5%. This increase was the first for Line 63 since 2001. These tariff increases mitigate the impact of declining throughput.

Storage and Distribution

We provide storage and distribution services to refineries in the Los Angeles Basin. The fundamental items impacting our storage and distribution revenue are the amount of storage capacity we have under lease, the lease rates for that capacity and the length of each lease. Demand for crude oil storage capacity tends to be more stable over time and leases for crude oil storage capacity are usually long term (more than one year). Demand for storage capacity for other dark products is less stable than for crude oil storage and varies depending on, among other things, refinery production runs and maintenance activities. Leases for dark products storage capacity are usually short term (less that one year). One of our business goals is to convert a number of dark products tanks to more flexible crude oil service (which can also accommodate other dark products); we currently await permit approvals for one such tank conversion and plan to convert a second tank in 2005.

While PT's rates are regulated by the CPUC, the CPUC has authorized PT to establish its rates based on market conditions through negotiated contracts.

Pipeline Buy/Sell Transportation Revenue

Throughput on our Rangeland system, which was acquired in the second quarter of 2004 and which includes the Rangeland and MAPL pipelines, varies with many of the same factors described in "Pipeline Transportation" above. In addition, following completion of our Edmonton initiation station, scheduled for completion in the fourth quarter of 2005, throughput will vary with our success in attracting new supplies of synthetic crude oil to our system.

The Rangeland system operates as a proprietary system and, therefore, we take title to the crude oil that is gathered and transported. Pursuant to a transportation service agreement between RMC and

RPC, RMC controls the entire capacity of Rangeland pipeline. Customers who wish to transport product on Rangeland pipeline must either: (i) sell product to RMC at the inlet to the pipeline without repurchasing product from RMC; or (ii) sell product to RMC at an inlet point and repurchase such product at agreed upon delivery points for the price paid at the inlet to the pipeline plus an established location differential.

Substantially all of the pipelines that comprise the Rangeland system are subject to the jurisdiction of the Alberta Energy Utilities Board ("EUB"). The Canadian portion of the segment of the Rangeland system owned by APC that connects to the Western Corridor system at the U.S.-Canadian border is subject to the Canadian National Energy Board ("NEB"). Neither the EUB nor the NEB will generally review rates set by a crude oil pipeline operator unless it receives a complaint.

Effective December 1, 2004, we increased the location differentials on the Rangeland pipeline.

Gathering and Blending

We purchase, gather, blend and resell crude oil in our PMT operations. Our PMT gathering and blending system in California's San Joaquin Valley is a proprietary intrastate operation that is not regulated by the CPUC or the FERC. It is complementary to our West Coast pipeline transportation business. The gathering network effectively extends our pipeline network to capture additional supplies of crude oil for transportation on our trunk pipelines to Los Angeles.

The contribution of our PMT gathering and blending operations is, for several reasons, a variable part of our income. First, it varies with the price differential between the cost of the varying grades of crude oil and natural gasoline PMT buys for use in its blending operations and the price of the blended crude oil it sells. Costs and sales prices are impacted by crude oil prices generally, as well as by local supply and demand forces, including regulations affecting refined product specifications. Second, it varies with the price differential between crude oil purchased on one price basis and sold on a different price basis. Finally, it varies with the volumes gathered and blended. We seek to control these variations through our risk management policy, which provides specific guidelines for our crude oil marketing and hedging activities and requires oversight by our senior management.

Our blending margins are a function of the cost of the heavy and light crude oils and natural gasoline that we buy and blend, relative to the price of the blended crude oil we sell. Blending margins exceeded their historical averages in the first eight months of 2004; however, since September 2004, blending margins have been below their historical averages. Foreign imports of crude oil into the Los Angeles Basin were highly discounted relative to West Texas Intermediate ("WTI") prices, which reduced demand for and prices of local California crude oil, including crude oil gathered and blended by us in the San Joaquin Valley. As the demand for and price of our blended crude oil has fallen, we have taken action to cancel certain purchase contracts beginning in the fourth quarter 2004, and to reduce the volume we gather, blend and sell. In addition, margins on one particular contract declined as the difference between purchases made on a WTI price basis and sales made on a West Coast price basis deviated from historical norms. This situation is expected to continue through this contract's maturity at the end of the first quarter of 2005.

Acquisitions and New Projects

We intend to continue to pursue acquisitions and new projects for development of additional midstream assets, including pipeline, storage and terminal facilities. We also intend to expand, principally by acquisition, into the refined product and natural gas storage and transportation businesses. We expect the acquisitions and new projects will be accretive to our cash flow and complement our existing business. We expect to fund acquisitions and new projects with a combination of debt and additional Partnership units, including common units. We expect to maintain a debt to total capitalization ratio of approximately 50 percent over time.

Operating Expenses

A substantial portion of the operating expenses we incur, including the cost of field and support personnel, maintenance, control systems, telecommunications, rights-of-way and insurance, varies little with changes in throughput. Certain of our costs, however, do vary with throughput, the most material being the cost of power used to run pump stations along our pipelines. Major maintenance costs can vary depending on a particular asset's age and also with regulatory requirements, such as mandatory inspections at defined intervals. Unanticipated costs can include the costs of cleanup of any release of oil to the extent not covered by insurance.

Employees

We do not have any employees, except in Canada. Our General Partner provides employees to conduct our U.S. operations. We and our General Partner collectively employ approximately 315 individuals who directly support our operations. We consider employee relations to be good. None of these employees are subject to a collective bargaining agreement. Our General Partner does not conduct any business other than with respect to the Partnership. All expenses incurred by our General Partner are charged to us.

Impact of Foreign Exchange Rates

Assets and liabilities of our Canadian subsidiaries are translated to U.S. dollars using the applicable exchange rate as of the end of a reporting period. Revenues, expenses and cash flow are translated using the average exchange rate during the reporting period. The reported cash flow of our Canadian operations is based on the U.S. dollar equivalent of such amounts measured in Canadian dollars. The results of our Canadian operations and distributions from our Canadian subsidiaries to the Partnership may vary in U.S. dollar terms based on fluctuations in currency exchange rates irrespective of our Canadian subsidiaries' underlying operating results. In addition, the amount of monies we repatriate from Canada will vary with fluctuations in currency exchange rates and may impact the cash available for distribution to our unitholders.

Critical Accounting Policies and Estimates

Our consolidated financial statements are prepared in conformity with accounting principles generally accepted in the United States, which require management to make estimates and assumptions that affect the reported amounts of the assets and liabilities and disclosures of contingent assets and liabilities as of the date of the balance sheet as well as the reported amounts of revenue and expenses during the reporting period. We routinely make estimates and judgments about the carrying value of our assets and liabilities that are not readily apparent from other sources. Such estimates and judgments are evaluated and modified as necessary on an ongoing basis. We believe that of our significant accounting policies (see note 1, Significant Accounting Policies, to our consolidated financial statements) and estimates, the following may involve a higher degree of judgment and complexity:

- We routinely apply the provisions of purchase accounting when recording our acquisitions. Application of purchase accounting requires that we estimate the fair value of the individual assets acquired and liabilities assumed. The valuation of the fair value of the assets involves a number of judgments and estimates. In our major acquisitions to date, we have engaged an outside valuation firm to provide us with an appraisal report, which we utilized in determining the purchase price allocation. The allocation of the purchase price to different asset classes impacts the depreciation expense we subsequently record. The principal assets we have acquired to date are property, pipelines, storage tanks and equipment.

- We depreciate the components of our property and equipment on a straight-line basis over the estimated useful lives of the assets. The estimates of the assets' useful lives require our judgment and our knowledge of the assets being depreciated. When necessary, the assets' useful lives are revised and the impact on depreciation is treated on a prospective basis.

We accrue an estimate of the undiscounted costs of environmental remediation for work at identified sites where an assessment has indicated it is probable that cleanup costs are or will be required and may be reasonably estimated. In making these estimates, we consider information that is currently available, existing technology, enacted laws and regulations, and our estimates of the timing of the required remedial actions. We use outside environmental consultants to assist us in making these estimates. In addition, generally accepted accounting principles in the United States of America require us to establish liabilities for the costs of asset retirement obligations when the retirement date is determinable. We will record such liabilities only when such date is determinable.

From time to time, a shipper or group of shippers may initiate a regulatory proceeding or other action challenging the tariffs we charge or have charged. In such cases, we assess the proceeding on an ongoing basis as to its likely outcome in order to determine whether to accrue for a future expense. We use outside regulatory lawyers and financial experts to assist us in these assessments.

Our inventory of crude oil for our PMT gathering and blending operations, our Canadian operations and any inventory earned through our tariffs for the transportation of crude oil in our common carrier pipelines is carried in our accounts at the lower of cost or market value. Any significant quantity of inventory is hedged. On any unhedged portion, we are exposed to the potential for a write-down to market value.

Results of Operations

Year ended December 31, 2004 Compared to Year Ended December 31, 2003

Summary

Net income for the year ended December 31, 2004 was $35.7 million or $1.23 per diluted limited partner unit compared to $25.0 million or $1.09 per diluted limited partner unit for the year ended December 31, 2003.

Net income includes the operations of the Pacific Terminals storage and distribution system following its acquisition on July 31, 2003 and the operations of the Rangeland system after its acquisition on May 11, 2004 and its expansion by acquisition of the MAPL pipeline on June 30, 2004.

Internally, in our analysis of operating results, we consider the impact of unusual items that we believe affect comparability between periods. We also believe that providing a discussion and analysis of our results that is comparable year over year, provides a more accurate and thorough analysis of our results of operations. Following is a discussion of each of the unusual items that impacted the results of our operations.

Share of Frontier's rate case and litigation expense. In 2003, Frontier incurred an expense for a contract dispute and two tariff rate related matters. These matters related to early 2002 and prior years, so there is no impact on Frontier's current rates or revenues.

Write-down of idle property. In 2004, we recorded an $0.8 million write-down of idle property associated with the pending sale of an idle Pacific Terminals property.

Write-off of deferred financing cost and interest rate swap termination expense. In 2004, we recorded an expense related to the unamortized portion of deferred financing costs of $2.3 million for a term loan which was repaid in 2004 and incurred $0.6 million of expense to terminate related interest rate swaps.

The following table is a summary that shows our net income adjusted for the items mentioned above:

	Year ended December 31,			
	2004	2003	Change	Percent
	(In thousands, except per unit information)			
Net income	$ 35,729	$ 25,029	$ 10,700	43%
Add: Share of Frontier's rate case and litigation expense		1,621		
Write-down of idle property	800			
Write-off of deferred financing cost and interest rate swap termination expense	2,901			
	$ 39,430	$ 26,650	$ 12,780	48%

The increase in net income, adjusted for the unusual items mentioned above, reflects the benefit of (i) the operations, since July 2003, of Pacific Terminals storage and distribution system, (ii) higher volumes and revenue on the Rocky Mountain pipelines, and (iii) the operations of the Rangeland system acquired in May 2004. These increases were partially offset by lower volumes and revenue from the West coast pipelines and lower gathering and blending margins. There were approximately 26% more limited partner units outstanding in the twelve months ended December 31, 2004 due to the sale of additional common units to partially fund the acquisitions of the Pacific Terminals storage and distribution system, the Rangeland system and the MAPL pipeline.

Segment Information

	Year ended December 31,			
West Coast	2004	2003	Change	Percent
	(In thousands)			
Operating income	$ 48,739	$ 42,664	$ 6,075	14%
Operating data:				
Pipeline throughput (bpd)	141.2	151.0	(9.8)	-6%

For the year ended December 31, 2004, operating income was $48.7 million, after the $0.8 million impairment expense, compared to $42.7 million for the year ended December 31, 2003. This increase was primarily attributable to a full year benefit of the Pacific Terminals storage and distribution system, which was acquired on July 31, 2003. PMT experienced lower gathering and blending margins in the third and fourth quarters of 2004, as well as reduced demand for PMT's blended crude. We consider this gathering and blending activity to be complementary to our pipeline transportation operations. Pipeline volumes for the year ended December 31, 2004 were 6% lower than in the year ended 2003, primarily due to OCS production declines, as well as increased crude runs by Bakersfield refineries, which reduced the volumes available to move south to Los Angeles. Helping to offset lower volumes were increased tariff rates on Line 2000 in May 2004 and Line 63 in November 2004, and a more favorable tariff mix.

Rocky Mountains	Year ended December 31, 2004	2003	Change	Percent
	(In thousands)			
Operating income	$ 23,729	$ 13,078	$ 10,651	81%
Operating data (bpd):				
Rangeland pipeline system:				
Sundre North	21.0		21.0	%
Sundre South	48.1		48.1	%
Western Corridor system	20.2	16.7	3.5	21%
Salt Lake City Core system	115.1	107.5	7.6	7%
Frontier pipeline	47.4	41.7	5.7	14%

For the year ended December 31, 2004, operating income was $23.7 million compared to $13.1 million for the year ended December 31, 2003. The Rangeland system was acquired in the second quarter of 2004. In addition, strengthened demand at Billings, Montana refineries in the latter half of the year, as well as increased demand by the Salt Lake City, Utah, refineries, helped drive higher pipeline volumes on all U.S. Rocky Mountain systems. The 7,000 bpd expansion completed in the second quarter of 2004 further increased volumes into Salt Lake City. We are currently evaluating a second expansion phase into Salt Lake City to meet increasing demand.

Statement of Income Discussion and Analysis

Revenues	Year ended December 31, 2004	2003	Change	Percent
	(In thousands)			
Pipeline transportation revenue	$ 108,395	$ 101,811	$ 6,584	6%
Storage and distribution revenue	37,577	12,711	24,866	196%
Pipeline buy/sell transportation revenue	18,640		18,640	
Crude oil sales, net of purchases:				
Crude oil sales	419,070	379,747	39,323	10%
Crude oil purchases	(402,283)	(358,454)	43,829	12%
Crude oil sales, net of purchases	16,787	21,293	(4,506)	21%
Net revenue before expenses	$ 181,399	$ 135,815	$ 45,584	34%

Increased pipeline transportation revenue was realized by our U.S. Rocky Mountain pipelines due to increased demand by Salt Lake City area refineries and increased volumes of gathered and trucked barrels. This increase was partially offset by lower West Coast pipeline revenues due to natural field production decline, and increased crude runs by Bakersfield refineries which reduced the volumes available to move south to Los Angeles. Helping to offset lower California volumes were increased tariffs and a more favorable tariff mix.

Higher storage and distribution revenue in 2004 reflects a full year of operations of the Pacific Terminals storage and distribution system, which was acquired on July 31, 2003. In addition, capacity was expanded, utilization rates increased and storage rates per barrel were also higher.

Pipeline buy/sell transportation revenues of $18.6 million relate to the operations of the Rangeland system, which was acquired on May 11, 2004.

The decrease in net crude oil sales for 2004 was primarily the result of lower margin blending activities in our West Coast operations, particularly due to lower blending volumes as a result of a change in refined products specifications and competitive pricing pressures as a result of cheaper foreign crude entering the West Coast markets. Higher oil prices increased gross sales and purchases values. We consider this gathering and blending activity to be complementary to our pipeline transportation operations.

	Year ended December 31,			
Expenses	**2004**	**2003**	**Change**	**Percent**
		(In thousands)		
Operating expenses	$ 84,729	$ 60,649	$ 24,080	40%
Transition costs	557	397	160	40%
General and administrative expense	15,400	13,705	1,695	12%
Depreciation and amortization	24,173	18,865	5,308	28%
	$ 124,859	$ 93,616	$ 31,243	33%

The increase in operating expense was related primarily to the acquisition of the Pacific Terminals storage and distribution assets on July 31, 2003 and the Rangeland system on May 11, 2004. We also experienced higher operating costs in the Rocky Mountains for maintenance and power costs, as well as the use of a flow improvement agent that increases throughput.

Transition costs in 2003 consisted of employee transition bonus payments related to our purchase of the Western Corridor and Salt Lake City Core systems in 2002. Transition costs in 2004 were incurred for transition services provided by the sellers of the Rangeland system and the MAPL pipeline, as well as for consulting and other out-of-pocket costs incurred in connection with the integration effort.

The increase in general and administrative expense was in part due to the acquisition of the Rangeland system in May 2004, increased costs for regulatory compliance and increased personnel costs related to company growth.

The increase in depreciation and amortization includes $2.0 million for depreciation on the Pacific Terminals storage and distribution system, reflecting a full year in 2004, and $3.6 million for depreciation on the Rangeland system. These increases were partly offset by lower depreciation on other assets that have now been fully depreciated.

	Year ended December 31,			
Other Income and Expense	**2004**	**2003**	**Change**	**Percent**
		(In thousands)		
Share of net income (loss) of Frontier:				
Income before rate case and litigation expense	$ 1,328	$ 1,459	$ (131)	-9%
Rate case and litigation expense	$	$ (1,621)	$ 1,621	%
Write-down of idle property	$ 800	$	$ 800	%
Interest expense	$ 19,209	$ 17,487	$ 1,722	10%
Other income	$ 1,032	$ 479	$ 553	115%
Write-off of deferred financing cost and interest rate swap termination expense	$ 2,901	$	$ 2,901	%
Income tax expense	$ 261	$	$ 261	%

The decrease in our share of Frontier's net income was attributable to increased major maintenance costs and costs of a flow improvement agent used to increase pipeline throughput, partly offset by increased revenues. In 2003, we incurred an expense for a contract dispute and two tariff rate related matters. These matters related to early 2002 and prior years, so there is no impact on Frontier's current rates or revenues.

The $0.8 million write-down of idle property in 2004 is a non-cash impairment expense associated with the pending sale of an idle Pacific Terminals property.

The increase in interest expense was due to borrowings incurred to partially fund the acquisition of the Pacific Terminals storage and distribution system and the Rangeland system. Our weighted average borrowings during the twelve months ended December 31, 2004 were $315.3 million compared to $260.2 million in the corresponding period in 2003. The effect of this increase was partially offset by a decrease in interest expense associated with a renegotiation of interest rates in December 2003 under our credit facilities as well as lower floating interest rates. The combination of lower renegotiated interest rates and lower market rates led to a lower weighted average interest rate of 6.2% for 2004 compared to a weighted average interest rate of 6.7% in 2003.

Other income of $1.0 million in 2004 was $0.6 million greater than in 2003 due to increased rental income from surplus facility space and a foreign currency gain.

Write-off of deferred financing cost and interest rate swap termination expense relate to the unamortized portion of deferred financing costs of $2.3 million for a term loan that was repaid in 2004 and $0.6 million of expense incurred to terminate related interest rate swaps.

The income tax expense for year ended December 31, 2004 relates to the income of the Rangeland system acquired in the second quarter of 2004. Our Canadian subsidiaries are taxable entities and certain kinds of repatriation of funds into the U.S. are subject to Canadian withholding tax.

Year ended December 31, 2003 Compared to Year Ended December 31, 2002

Summary

	Year ended December 31,			
	2003	**2002**	**Change**	**Percent**
		(In thousands)		
Net income	$ 25,029	$ 33,574	$ (8,545)	25%

Basic and diluted net income per limited partner unit for 2003 was $1.10 and $1.09 per limited partner unit, respectively. We completed our initial public offering in July 2002, so there is no directly comparable per unit calculation for 2002.

Net income for 2003 includes five months of operations of the Pacific Terminals storage and distribution system following the acquisition of these assets on July 31, 2003. Net income for 2002 includes the results of the Western Corridor and Salt Lake City Core system assets for the ten months following the acquisition of these assets on March 1, 2002.

The additional income generated by the Pacific Terminals storage and distribution system assets and the Western Corridor and Salt Lake City Core systems was more than offset by a combination of lower West Coast pipeline volumes and increased expenses. The increased expenses include increased general and administrative expense associated with our growth and becoming a public company in July 2002, and increased interest expense associated with our post-IPO capital structure.

Segment Information

West Coast	Year ended December 31, 2003	2002	Change	Percent
	(In thousands)			
Operating income	$ 42,664	$ 38,323	$ 4,341	11%
Operating data:				
Pipeline throughput (bpd)	151.0	162.8	(11.8)	-7%

The increase in West Coast operating income was primarily due to the acquisition of the Pacific Terminals storage and distribution system. This increase was partially offset by a reduction in pipeline transportation revenue as average daily pipeline throughput decreased to 151,000 bpd for the year ended December 31, 2003, compared to 162,800 bpd for the prior year. California OCS throughput to the Los Angeles Basin was lower during 2003, compared to 2002, primarily due to maintenance downtime at both on-shore processing and off-shore production facilities. Refinery maintenance activities and increased mid-barrel crude oil ("MBCO") demand in San Francisco reduced throughput to the Los Angeles Basin. Increased demand for light crude oil at refineries in Bakersfield also reduced throughput to the Los Angeles Basin. In addition, the natural decline of OCS and San Joaquin Valley production reduced available crude supplies.

Rocky Mountains	Year ended December 31, 2003	2002	Change	Percent
	(In thousands)			
Operating income	$ 13,078	$ 13,482	$ (404)	-3%
Operating data (bpd):				
Western Corridor system	16.7	15.0	1.7	11%
Salt Lake City Core system	107.5	115.6	(8.1)	-7%
Frontier pipeline	41.7	44.4	(2.7)	-6%

Operating income for the 2002 period included only ten months of results for the Western Corridor and Salt Lake City Core systems. We incurred significant transition costs in the 2002 period, but those costs did not recur in the 2003 period. The reduction in transition costs in 2003 was offset, however, by increased maintenance expense. Refinery maintenance in the first half of 2003 resulted in reduced throughput to Salt Lake City through our various pipeline systems.

Statement of Income Discussion and Analysis

Revenues	Year ended December 31, 2003	2002	Change	Percent
	(In thousands)			
Pipeline transportation revenue	$ 101,811	$ 103,090	$ (1,279)	-1%
Storage and distribution revenue	12,711		12,711	
Crude oil sales, net of purchases:				
Crude oil sales	379,747	337,387	42,360	13%
Crude oil purchases	(358,454)	(316,283)	42,171	13%
Crude oil sales, net of purchases	21,293	21,104	189	1%
Net revenue before operating expenses	$ 135,815	$ 124,194	$ 11,621	9%

Rocky Mountain pipeline transportation revenue increased by $3.3 million compared to the corresponding period in 2002 due to revenue generated by the Western Corridor and Salt Lake City

Core systems for twelve months in 2003 compared to ten months in 2002. The increase in Rocky Mountain pipeline transportation revenue for 2003 was more than offset by a decrease in West Coast pipeline transportation revenue due to lower throughput.

The acquisition of the Pacific Terminals storage and distribution system on July 31, 2003, resulted in storage and distribution revenue of $12.7 million for the period ended December 31, 2003.

The increase in crude oil sales and purchases for 2003 was primarily the result of higher crude oil prices. We consider this activity to be complementary to our pipeline transportation operations.

	Year ended December 31,			
Expenses	**2003**	**2002**	**Change**	**Percent**
		(In thousands)		
Operating expenses	$ 60,649	$ 55,184	$ 5,465	10%
Transition costs	397	2,633	(2,236)	-85%
General and administrative expense	13,705	7,515	6,190	82%
Depreciation and amortization	18,865	15,919	2,946	19%
	$ 93,616	$ 81,251	$ 12,365	15%

The increase in operating expense was related primarily to the acquisitions of the Pacific Terminals storage and distribution system and a full year of operations of the Western Corridor and Salt Lake City Core systems. We also experienced higher operating costs as a result of increased requirements for pipeline and storage tank inspections, and increased costs for property taxes and insurance.

Operating expense for our Rocky Mountain Business Unit increased by $3.2 million due to a full year of operations of the Western Corridor and Salt Lake City Core systems compared to ten months of operations for the corresponding period in 2002 and a return to a normal level of maintenance activity. These increases were partially offset by a reduction of $2.1 million in transition costs. Operating expense for our West Coast operations increased by $3.8 million as a result of incurring five months of operating expense relating to the Pacific Terminals storage and distribution system. This was partially offset by decreased operating expense for our West Coast pipeline and gathering and blending operations due to lower field operating expenses and reduced right-of-way expense resulting from the relinquishment of certain unused rights-of-way on Line 2000.

Transition costs in 2003 consisted only of employee transition bonus payments, whereas transition costs in 2002 consisted of payments to the seller of the Western Corridor and Salt Lake City Core systems for certain interim operations support, financial systems services and employee transition bonuses.

The increase in general and administrative expense includes $3.2 million of expense for long-term incentive awards. The balance of the increase is attributable to additional costs incurred as a result of the acquisition of the Western Corridor and Salt Lake City Core systems and higher costs of being a public company, including costs incurred as a result of new stock exchange and SEC rules.

The increase in depreciation and amortization includes $1.2 million for a full year of depreciation on the Western Corridor and Salt Lake City Core systems in 2003, compared to ten months in 2002, and $1.4 million for five months of depreciation on the Pacific Terminals storage and distribution system.

Other Income and Expenses	**Year ended December 31, 2003**	**2002**	**Change**	**Percent**
	(In thousands)			
Share of net income (loss) of Frontier				
Income before rate case and litigation expense	$ 1,459	$ 1,904	$ (445)	-23%
Rate case and litigation expense	$ (1,621)	$ (557)	$ 1,064	191%
Interest expense	$ 17,487	$ 11,634	$ 5,853	50%

Our decreased share of Frontier net income was attributable to expenses related to a contract dispute and two tariff rate related matters. Tariff revenue per barrel was greater in the first quarter of 2002 than in the subsequent periods.

Interest expense increased by $5.9 million, including $1.2 million attributable to an increase in borrowings during the 2003 period to finance the acquisition of the Pacific Terminals storage and distribution system. The remaining increase was primarily due to an increase in the interest rate on outstanding borrowings during 2003. Our interest rate on outstanding borrowings averaged 6.7% for 2003, as compared to 5.0% during 2002, reflecting an increase in the percentage of fixed rate debt in our post initial public offering capital structure.

Liquidity and Capital Resources

We believe that cash generated from operations, together with our cash balance and our unutilized borrowing capacity, will be sufficient to meet our planned distributions, our working capital requirements and anticipated sustaining capital expenditures in the next three years. We expect to extend or replace our revolving credit facilities, which mature in mid-2007.

The financing plan for the construction of our proposed Pier 400 project will likely include both proceeds from debt and the issuance of additional Partnership units. The final structure will depend on market conditions.

On August 1, 2003, the Partnership, PEG and certain subsidiaries of PEG filed a universal shelf registration statement on Form S-3 with the SEC to register the issuance and sale, from time to time and in such amounts as determined by the market conditions and needs of the Partnership, of up to $550.0 million of common units of the Partnership and debt securities of both the Partnership and PEG. The SEC declared the registration statement effective on August 8, 2003. At December 31, 2004, we have approximately $280 million of remaining availability under this registration statement.

We intend to draw down on this shelf registration statement, file additional registration statements and use proceeds from borrowings under our existing and planned revolving credit facilities to finance our future acquisitions and development projects, including our Pier 400 project. We expect to maintain a debt to total capitalization ratio of approximately 50% over time.

We have filed an application with the CPUC to sell surplus Pacific Terminals properties, which we believe are worth approximately $10 million.

Our ability to satisfy our debt service obligations, fund planned capital expenditures, make acquisitions, develop projects and pay distributions to our unitholders will depend upon our future operating performance. Our operating performance is primarily dependent on the volume of crude oil transported through our pipelines and the capacity leased in our storage tanks as described in "Overview" above. Our operating performance is also affected by prevailing economic conditions in the crude oil industry and financial, business and other factors, some of which are beyond our control, which could significantly impact future results.

Operating, Investing and Financing Activities

	Year ended December 31,		
	2004	**2003**	**2002**
		(In thousands)	
Net cash provided by operating activities	$ 57,226	$ 42,754	$ 45,793
Net cash used in investing activities	(155,952)	(180,332)	(101,311)
Net cash provided by financing activities	112,410	123,404	69,880

Net cash provided by operating activities

Net cash from operations was higher in 2004 than 2003, primarily because of a full year's operation of our Pacific Terminals storage and distribution system and the purchase of the Rangeland system, which contributed to higher operating income. In addition, we experienced higher volumes and revenue on our U.S. Rocky Mountain pipelines. These increases were partially offset by lower volumes and revenue from the West coast pipelines and lower gathering and blending margins. Net cash from operating activities in 2004 was reduced by approximately $6.8 million for working capital purposes.

The decrease in the net cash from operating activities from 2002 to 2003 of $3.0 million, or 7%, was the net result of higher operating income, offset by increased interest expense relating to our post initial public offering capital structure, and an increase in cash used for working capital.

Net cash used in investing activities

The amounts in 2004 related primarily to our acquisition activities. In 2004, we acquired the Rangeland system and the MAPL pipeline for a net cash outlay of approximately $138.7 million. Capital expenditures were $16.5 million in 2004, of which $2.0 million related to sustaining capital projects, $1.8 million related to the transition of the Pacific Terminals storage and distribution system and the Rangeland system and $7.5 million related to expansion. Additionally, we continue to develop our Pier 400 Project, which we began in 2003. We capitalized $5.2 million and $5.3 million for our Pier 400 Project for the years ended December 31, 2004 and 2003, respectively.

In 2003, we acquired the Pacific Terminals storage and distribution system for a net cash outlay of $169.7 million. Capital expenditures were $10.9 million in 2003, of which $2.1 million related to sustaining capital projects, $0.3 million related to the transition of RMPS and the Pacific Terminals storage and distribution system, and $8.4 million related to expansion, including the Pier 400 expenditures noted above.

In 2002, we acquired the Western Corridor and Salt Lake City Core systems for approximately $107.0 million with a cash outlay of $95.7 million in 2002 (the balance was paid in 2001). In 2002, capital expenditures were $5.6 million, of which $2.8 million related to sustaining capital projects, $2.0 million related to the transition of RMPS assets, and $0.8 million related to expansion.

Net cash provided by financing activities

Cash provided by financing activities in 2004 included net proceeds of $128.6 million from an equity offering completed in April 2004, and $240.9 million net proceeds from our Senior Note offering completed in June 2004. We repaid a $225 million term loan with the proceeds of the Senior Note offering and had $25.6 million of net borrowings under our U.S. and Canadian revolving credit facilities. We incurred $1.2 million of costs to establish our Canadian revolving credit facility. We made $56.5 million in distributions to our limited and general partner interests.

The equity offering in 2004 was used to fund a portion of the Rangeland system and the MAPL pipeline acquisitions and to repay a portion of our U.S. revolving credit facility. Borrowings under a new Canadian revolving credit facility were also used to fund the Rangeland system and the MAPL pipeline acquisitions.

The amount in 2003 of $123.4 million includes net proceeds of $73.0 million under our revolving credit facility and net proceeds of $92.9 million, after deducting the related redemption of common units, from an equity offering completed on August 25, 2003, which were used to fund the acquisition of the Pacific Terminals storage and distribution system. The cash provided from financing activities in 2003 is net of $42.1 million in distributions to our limited partners and our General Partner.

The 2002 amount of $69.9 million includes capital contributed by members to PEG prior to our initial public offering of $8.8 million and distributions to members by PEG of $16.0 million prior to our initial public offering. In March 2002, net proceeds of $87.0 million from notes payable were used to fund the acquisition of the Western Corridor and Salt Lake City Core systems. In connection with our initial public offering, net proceeds of $151.1 million from the issuance of common units were used to repay a similar amount of debt. Proceeds of $225.0 million from the term loan were used to pay debt issuance costs of $5.3 million, repay $114.6 million in debt and fund distributions of $105.1 million to our General Partner. Distributions to the limited and general partner interests subsequent to our initial public offering were $7.2 million in 2002.

Capital Requirements

Generally, our crude oil transportation and storage operations require investment to upgrade or enhance existing operations and to meet environmental and operational regulations. Our capital requirements consist primarily of:

- sustaining capital expenditures to replace partially or fully depreciated assets in order to maintain the existing operating capacity or efficiency of our assets and extend their useful lives;

- transitional capital expenditures to integrate acquired assets into our existing operations; and

- expansion capital expenditures to expand or increase the efficiency of the existing operating capacity of our assets, whether through construction or acquisition, such as placing new storage tanks in service to increase our storage capabilities and revenue, and adding new pump stations or pipeline connections to increase our transportation throughput and revenue.

The following table summarizes sustaining, transitional and expansion capital expenditures for the periods presented:

	Year Ended December 31,		
	2004	**2003**	**2002**
		(in thousands)	
Sustaining capital expenditures	$ 1,953	$ 2,149	$ 2,725
Transitional capital expenditures	1,874	351	2,039
Expansion capital expenditures	12,693	8,392	878
Total	$ 16,520	$ 10,892	$ 5,642

We have budgeted total capital expenditures of $37.0 million for 2005, including $20.5 million for expansion projects, $2.7 million for our Pier 400 project, $11.3 million for transitional capital projects and $2.5 million for sustaining capital projects. Included in expansion projects are: $10.0 million for additional tankage for our integrated pipeline corridor from Edmonton, Alberta to Salt Lake City, Utah; and $7.9 million for expansion of our Pacific Terminals storage and distribution system. Included in the transitional capital budget is $9.6 million (Cdn$12 million) for our Edmonton initiating station and terminal.

Credit Facilities and Long-Term Debt

Our long-term debt obligations at December 31, 2004 and 2003 are shown below:

	December 31,			
	2004		2003	
	(in thousands)			
Senior secured U.S. revolving credit facility	$	51,000	$	73,000
Senior secured Canadian revolving credit facility		54,005		
Senior notes, net of unamortized discount of $4,202 and including fair value increase of $2,693		248,491		
Senior secured term loan				225,000
Future payment for MAPL assets, net of unamortized discount of $480		3,667		
Total		357,163		298,000
Less current portion				
Long-term debt	$	357,163	$	298,000

Senior Secured U.S. Revolving Credit Facility and Term Loan

The U.S. revolving credit facility is a $200.0 million facility which matures on July 26, 2007 and is available for general purposes, including working capital, letters of credit and distributions to unitholders, and to finance future acquisitions. Borrowings under the revolving credit facility are limited by various financial covenants in the credit agreement. The revolving credit facility has a borrowing sublimit of $45.0 million for working capital, letters of credit and distributions to unitholders. There are limitations on additional investment in our Canadian subsidiaries.

The U.S. revolving credit facility bears interest at our option, at either (i) the base rate, which is equal to the higher of the prime rate as announced by Fleet National Bank or the Federal Funds rate plus 0.50% or (ii) LIBOR plus an applicable margin ranging from 0.75% to 2.00%. The applicable margins are subject to change based on the credit rating of the revolving credit facility or, if is not rated, the credit rating of our U.S. operating subsidiary, PEG. We incur a commitment fee which ranges from 0.125% to 0.375% per annum on the unused portion of the revolving credit facility.

As of December 31, 2004, $51.0 million was outstanding under the revolving credit facility and $106 million of undrawn credit was available under the credit facility. With the consent of the administrative agent under the revolving credit facility, we can increase credit availability under the credit facility by up to an additional $43 million, based upon pro-forma EBITDA from future acquisitions.

The revolving credit facility is the primary obligation of PEG and is guaranteed by the Partnership and certain of our U.S. operating subsidiaries, and PEG Canada, PEG Canada GP LLC and Pacific Energy Finance Corporation (collectively, the "Guarantors"). The revolving credit facility is fully recourse to us and the Guarantors, but non-recourse to our General Partner. Obligations under the revolving credit facility are secured by (i) the assets of the Partnership, (ii) pledges of membership interests in and the assets of certain of our U.S. operating subsidiaries and PEG Canada GP LLC, (iii) pledges of partnership interests in and certain assets of PEG Canada, and (iv) pledges of the shares in and the assets of Pacific Energy Finance Corporation; provided, however, that the collateral under the credit agreement does not include shares, partnership interests, limited liability company membership interests or other ownership interest, if any, in or assets of RPC, RMC, RNPC, RPP, APC or any other entity that is designated by us after the date hereof as an "Unrestricted Subsidiary" pursuant to the terms of the U.S. credit agreement.

Under the U.S. credit agreement, we are prohibited from declaring dividends or distributions if any event of default, as defined in the credit agreement, occurs or would result from such declaration. In addition, the credit agreement contains certain financial covenants and covenants limiting the ability of the Guarantors to, among other things, incur or guarantee indebtedness, change ownership or structure, including mergers, consolidations, liquidations and dissolutions, sell or transfer their assets and properties, declare or pay dividends and enter into a new line of business. At December 31, 2004, we were in compliance with all such covenants.

On June 16, 2004, we repaid all amounts outstanding under the term loan. Amounts under the term loan that have been repaid may not be re-borrowed.

In connection with the LB Acquisition, we amended our credit facility to account for the change in control of our General Partner.

Canadian Revolving Credit Facility

On May 11, 2004, one of our Canadian subsidiaries, RPC, entered into a Cdn$100 million revolving credit facility agreement which is guaranteed by our other Canadian subsidiaries. The Canadian revolving credit facility is secured by liens on all of the property and assets of our Canadian subsidiaries.

Indebtedness under the Canadian revolving credit facility bears interest, at our option, at either (i) the Canadian prime rate or the U.S. base rate (each plus an applicable margin ranging from 1.00% to 1.625%), or (ii) Bankers' Acceptance discount rates, or LIBOR plus an applicable margin ranging from 2.00% to 2.65%. The applicable margins are subject to change based on certain financial ratios.

The Canadian revolving credit facility matures on May 11, 2007. Amounts outstanding under the credit facility may be repaid at any time prior to maturity.

The Canadian revolving credit facility is available for general corporate purposes of our Canadian subsidiaries and also provides for the issuance of letters of credit. At December 31, 2004, borrowings totaling Cdn$65.0 million (U.S.$54.0 million) and letters of credit totaling Cdn$5.0 million (U.S.$4.1 million) were outstanding under the Canadian revolving credit facility. As of December 31, 2004, we had available but undrawn credit of Cdn$21 million (U.S.$17 million) under our Canadian revolving credit facility.

We incur a commitment or standby fee which ranges from 25% to 35% of the applicable margin, based on the unused portion of the Canadian revolving credit facility. Under the Canadian credit agreement, RPC and its Canadian affiliates are prohibited from declaring dividends or making any other distributions or payments to their U.S. parent or its affiliates if any default or event of default, as defined in the Canadian credit agreement, occurs or would result from such declaration or payment, or if a material adverse effect, as defined in the Canadian credit agreement, would result from such declaration or payment, or if the distributions and payments would exceed certain limits. The Canadian credit agreement also contains covenants requiring RPC and its Canadian affiliates to maintain specified financial ratios. In addition, the Canadian credit agreement contains other restrictive covenants. As of December 31, 2004, we were in compliance with all covenants under the Canadian credit agreement.

In connection with the LB Acquisition, we amended our credit facility to account for the change in control of our General Partner.

7 1/8% Senior Notes

On June 16, 2004, we completed the sale of $250 million of the Senior Notes. The Senior Notes were sold in a private offering to qualified institutional buyers in reliance on Rule 144A under the Securities Act and to non-U.S. persons under Regulation S under the Securities Act. On September 2, 2004, we filed a Registration Statement on Form S-4 to register the Senior Notes under the Securities Act. On September 23, 2004, we commenced an exchange offer, which allowed the holders of the Senior Notes to exchange the unregistered Senior Notes for new registered notes having materially identical terms as the unregistered notes. The exchange offer expired on October 29, 2004, with all of the unregistered Senior Notes having been exchanged for registered Senior Notes. The Senior Notes are not listed on any securities exchange.

The Senior Notes were issued at a discount of $4.4 million, resulting in an effective interest rate of 7.375%. Interest payments are due on June 15 and December 15 of each year, beginning on December 15, 2004. At any time prior to June 15, 2007, we have the option to redeem up to 35% of the aggregate principal amount of notes at a redemption price of 107.125% of the principal amount with the net cash proceeds of one or more equity offerings. We have the option to redeem the Senior Notes, in whole or in part, at anytime on or after June 15, 2009 at the following redemption prices:

Year	Percentage
2009	103.563%
2010	102.375%
2011	101.188%
2012 and thereafter	100.000%

The Senior Notes are jointly and severally guaranteed by certain of our subsidiaries.

In addition, the indenture governing the Senior Notes contains certain covenants that, among other things, limit our ability to incur or guarantee indebtedness or issue certain types of preferred equity securities; sell assets; pay distributions on, redeem or repurchase units; consolidate, merge or transfer all or substantially all of our assets. At December 31, 2004, we were in compliance with all such covenants.

Net proceeds from the issuance of the Senior Notes were $240.9 million after deducting the $4.4 million discount and offering expenses of $4.7 million. The net proceeds were used principally to repay our $225 million term loan and to repay $16 million of indebtedness outstanding under our U.S. revolving credit facility.

According to the terms of the Indenture, dated as of June 16, 2004 (the "Indenture"), by and among the Partnership, Pacific Energy Finance Corporation, the guarantors named therein, and Wells Fargo Bank, National Association, as trustee, which governs the Senior Notes, the sale of our General Partner followed by a Rating Decline (as such term is defined in the Indenture) within 90 days of such sale would constitute a "Change of Control" that would require us, following the closing of the sale, to make a "Change of Control Offer" to purchase all of the Senior Notes then outstanding at a purchase price equal to 101% of the aggregate principal amount, plus accrued and unpaid interest, if any, to the date of purchase.

The LB Acquisition, coupled with our recent downgrade by S&P, would have required us to make a "Change of Control Offer" pursuant to the Indenture. In order to avoid triggering the "Change of Control Offer" provision, we solicited the consent (the "Consent Solicitation") of the holders of the Senior Notes to amend certain provisions of the Indenture, including an amendment to the definition of "Change of Control." The Consent Solicitation commenced on January 28, 2005 and expired on February 10, 2005. During that time, a majority of the holders of the Senior Notes consented to the adoption of the proposed amendments and as such the proposed amendments were approved.

Thereafter, a supplemental indenture that incorporated the proposed amendments was executed by the parties to the Indenture. LBP and TAC reimbursed us for the costs of the Consent Solicitation.

Future Payment for MAPL Pipeline

In connection with the purchase of the MAPL pipeline, we are obligated to pay the seller Cdn$5.0 million (U.S.$4.2 million) on June 30, 2007. The future payment was discounted at 5%. The carrying value of the future payment was Cdn$4.4 million (U.S.$3.7 million) at December 31, 2004.

Contractual Obligations

In the performance of our operations, we are bound by certain contractual obligations. Following is a summary of our monetary contractual obligations as of December 31, 2004.

	Payments due by period				
Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
	(in thousands)				
Long-term debt principal repayments	$ 357,163	$	$ 108,672	$	$ 248,491
Right-of-way obligations(1)	78,298	3,744	8,127	8,581	57,846
Operating lease obligations	3,372	1,307	1,661	404	
Total	$ 438,833	$ 5,051	$ 118,460	$ 8,985	$ 306,337

(1) Right-of-way obligations reflect our commitment for the next 15 years assuming the current right-of-way agreements will be renewed during the period.

Long-Term Debt Principal Repayments

We expect to refinance the debt maturities in the "3-5 year" and "more than 5 year" categories above through an extension of existing credit facilities, new credit facilities and/or through the issuance of bonds or long-term notes.

Right-of-Way Obligations

We have secured various rights-of-way for our pipeline systems under right-of-way agreements, certain of which expire at various times through 2035, that provide for annual payments to third parties for access and the right to use their properties. Due to the nature of our operations, we expect to continue making payments and renewing the right-of-way agreements indefinitely. The annual amounts payable under certain of the right-of-way agreements are subject to fair market and inflation adjustments. Right-of-way payments, which are included in operating expenses, were $3.4 million, $2.9 million and $3.3 million in 2004, 2003 and 2002, respectively.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements. For a description of certain operating leases please see "Note 12 Commitments" to the accompanying consolidated financial statements.

Impact of Inflation

Inflation in the United States and Canada has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2004, 2003 or 2002.

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Environmental Matters

Our transportation and storage operations are subject to extensive regulation under federal, state and local environmental laws concerning, among other things, the generation, handling, transportation and disposal of hazardous materials, and we may be, from time to time, subject to environmental cleanup and enforcement actions.

The accompanying balance sheet includes reserves for environmental costs that relate to existing conditions caused by past operations. Estimates of ultimate liabilities associated with environmental costs are particularly difficult to make with certainty due to the number of variables involved, including the early stage of investigation at certain sites, the lengthy time frames required to complete remediation at most locations, the number of remediation alternatives available, the uncertainty of potential recoveries from third parties and the evolving nature of environmental laws and regulations.

Based on the information presently available, it is the opinion of management that our environmental costs, to the extent they exceed recorded liabilities, will not have a material adverse effect on our financial condition or results of operations.

Recent Accounting Pronouncements

In December 2004, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 123 (revised December 2004), *Share-Based Payment (SFAS 123R)*. This Statement is a revision of FASB Statement No. 123, *Accounting for Stock-Based Compensation*. SFAS 123R establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services. SFAS 123R is effective for the Partnership as of the beginning of the first interim period or annual reporting period that begins after June 15, 2005. The adoption of SFAS 123 is not expected to have a material impact on the Partnership's consolidated financial statements.

ITEM 7A. Quantitative and Qualitative Disclosures about Market Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. The principal market risks to which we are exposed are interest rate risk and crude oil price risk. Debt we incur under our credit facilities bears variable interest at either the applicable base or prime rate, a rate based on LIBOR or a rate based on Canadian Bankers' Acceptances. We have used and will continue to use from time to time derivative instruments to hedge our exposure to variable interest rates. In addition, we have entered into swap agreements to convert a portion of our fixed rate Senior Notes into floating rate debt based on LIBOR.

We use, on a limited basis, certain derivative instruments (principally futures and options) to hedge our exposure to market price volatility related to our inventory or future sales of crude oil. We do not enter into speculative derivative activities of any kind. The fair market values of derivative instruments are included in "Other Assets, net" in the accompanying consolidated balance sheets. In our PMT operations we purchase crude oil for subsequent blending, transportation and resale primarily in the Los Angeles Basin. Changes in the fair value of our derivative instruments related to crude oil inventory are recognized in net income. In 2004, 2003 and 2002, "crude oil sales, net of purchases" were net of $2.7, $0.3 and $0.4 million in losses, respectively, reflecting changes in the fair value of PMT's derivative instruments for its marketing activities. In addition, changes in the fair value of our derivative instruments related to the future sale of crude oil that qualify as hedges for accounting purposes are deferred and reflected in "accumulated other comprehensive income," a component of partners' capital, until the related revenue is recognized in the consolidated statements of income. As of December 31, 2004, $0.2 million relating to the changes in the fair value of derivative instruments was included in "accumulated other comprehensive income."

In connection with the issuance of the Senior Notes, we entered into interest rate swap agreements with an aggregate notional principal amount of $80.0 million to receive interest at a fixed rate of 7 1/8% and to pay interest at an average variable rate of six month LIBOR plus 1.6681% (set in advance or in arrears depending on the swap transaction). The interest rate swaps mature June 15, 2014 and are callable at the same dates and terms as the Senior Notes. We designated these swaps as a hedge of the change in the Senior Notes fair value attributable to changes in the six month LIBOR interest rate. Changes in fair values of the interest rate swaps are recorded into earnings each period. Similarly, changes in the fair value of the underlying $80.0 million of Senior Notes, which are expected to be offsetting to changes in the fair value of the interest swaps, are recorded into earnings each period. At December 31, 2004 we recorded an increase of $2.7 million in the fair value of interest rate swaps with an equal offsetting entry to the $80.0 million of Senior Notes. As of December 31, 2004, we measured the hedge effectiveness of this interest rate swap and noted that no gain or loss from ineffectiveness was required to be recognized.

We are subject to risks resulting from interest rate fluctuations as the interest cost on our credit facilities and the $80 million interest swap on the Senior Notes are based on variable rates. If the LIBOR or Canadian Bankers' Acceptance discount rates were to increase 1.0% in 2005 as compared to the rate at December 31, 2004, our interest expense for 2005 would increase $1.9 million based on our outstanding debt at December 31, 2004.

Fair Value of Financial Instruments

The carrying amount and fair values of financial instruments are as follows:

	December 31,			
	2004		2003	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(in thousands)			
Crude oil hedging futures	$ 400	$ 400	$ (173)	$ (173)
Fair value interest rate swaps	2,693	2,693		
Cash flow interest rate swaps			(5,436)	(5,436)
Long-term debt	357,163	373,265	298,000	298,000

As of December 31, 2004 and 2003, the carrying amounts of items comprising current assets and current liabilities approximate fair value due to the short-term maturities of these instruments. The carrying amounts of the revolving credit facilities approximate fair value primarily because the interest rates fluctuate with prevailing market rates. The interest rate on the 7.125% senior notes is fixed and the fair value is determined from a broker's price quote at December 31, 2004.

The carrying amount of derivative financial instruments represents the fair value as these instruments are recorded on the balance sheet at their fair value under SFAS 133. The Partnership's fair values of crude oil hedging futures are based on Reuters quoted market prices on the NYMEX. Interest rate swaps' fair values are based on the prevailing market price at which the positions could be liquidated.

ITEM 8. Financial Statements and Supplementary Data

The information required here is included in the report as set forth in the "Index to Financial Statements" on page F-1.

ITEM 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

ITEM 9A. Controls and Procedures

Disclosure Controls and Procedures

We have established disclosure controls and procedures to ensure that material information relating to the Partnership, including its consolidated subsidiaries, is made known to the officers who certify the Partnership's financial reports and to other members of senior management and the Board of Directors.

Based on their evaluation as of December 31, 2004, the principal executive officer and principal financial officer of the Partnership have concluded that the Partnership's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act)) are effective to ensure that the information required to be disclosed by the Partnership in the reports it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

Internal Control Over Financial Reporting Statement

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined under Rule 13a-15(f) of the Exchange Act. Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our evaluation under the framework in *Internal Control Integrated Framework,* our management concluded that our internal control over financial reporting was effective as of December 31, 2004. Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report which is included below.

Changes in Internal Controls

There has not been any change in our internal control over financial reporting that occurred during the year ended December 31, 2004 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors of Pacific Energy Management LLC and Unitholders of
Pacific Energy Partners, L.P.:

We have audited management's assessment, included in the accompanying *Internal Control Over Financial Reporting Statement*, that Pacific Energy Partners, L.P. (the "Partnership") maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Partnership's internal control over financial reporting based on our audit.

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

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

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

In our opinion, management's assessment that Pacific Energy Partners, L.P. maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also, in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Pacific Energy Partners, L.P. and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of income, partners' capital, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2004, and our report dated March 10, 2005, expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Los Angeles, California
March 10, 2005

ITEM 9B. Other Information

None.

Part III

ITEM 10. Directors and Executive Officers

We are managed by our General Partner, Pacific Energy GP, LP, a Delaware limited partnership. Prior to the LB Acquisition, our General Partner had been Pacific Energy GP, Inc., a corporation owned 100% by a subsidiary of TAC. Immediately prior to the closing of the LB Acquisition, Pacific Energy GP, Inc. was converted to Pacific Energy GP, LLC, a Delaware limited liability company; and immediately after the closing of the LB Acquisition, Pacific Energy GP, LLC was converted to Pacific Energy GP, LP.

In connection with the conversion of our General Partner to a limited partnership, our General Partner ceased to have a board of directors, and is now managed by its general partner, Pacific Energy Management LLC, a Delaware limited liability company ("PEM"), which is 100% owned by LBP. PEM has a board of directors (the "Board of Directors" or "Board") that manages the business and affairs of PEM and, thus, indirectly manages the business and affairs of our General Partner and the Partnership. All of the officers and employees of our General Partner were transferred to fill the same positions with PEM, and the Board established the same committees as had been maintained by our General Partner prior to the LB Acquisition. PEM also adopted our General Partner's compensation structure and its employee benefits plans and policies.

The following table shows information for the directors and executive officers of PEM as of March 4, 2005.

Name	Age	Position with the General Partner
Christopher R. Manning	37	Chairman of the Board of Directors
Forrest E. Wylie	41	Vice Chairman of the Board of Directors
Joshua L. Collins	40	Director
David L. Lemmon	62	Director
John C. Linehan	65	Director
Douglas L. Polson	63	Director
Jim E. Shamas	70	Director
William L. Thacker	59	Director
Jeffrey C. Weber	36	Director
Irvin Toole, Jr.	63	President, Chief Executive Officer and Director
David E. Wright	60	Executive Vice President, Corporate Development
Gerald A. Tywoniuk	43	Senior Vice President, Chief Financial Officer and Treasurer
Lynn T. Wood	53	Vice President, General Counsel and Secretary
Arthur G. Diefenbach	54	Senior Vice President, West Coast Business Unit
Gary L. Zollinger	56	Senior Vice President, Rocky Mountain Business Unit
Lyle B. Boarts	62	Vice President, Human Resources

Philip F. Anschutz and Clifford P. Hickey were directors until March 3, 2005, the closing date of the LB Acquisition.

Christopher R. Manning was elected Chairman of the Board of Directors in March 2005. Mr. Manning is a principal of LBMB and a Managing Director of Lehman Brothers. Mr. Manning joined the Natural Resources Group of Lehman Brothers in 1997 and joined LBMB in 2000. Prior to joining Lehman Brothers, Mr. Manning was Chief Financial Officer of The Wing Group, a developer of international power projects. Prior to The Wing Group, Mr. Manning was in the investment banking department of Kidder, Peabody & Co. Mr. Manning is a member of the Nominating and Governance and Compensation Committees of the Partnership.

Forrest E. Wylie was elected Vice Chairman of the Board of Directors in March 2005. Mr. Wylie was President and Chief Financial Officer of NuCoastal Corporation since May 2002. Prior to NuCoastal, Mr. Wylie served as Senior Vice President, Natural Gas Trading, for both The Coastal Corporation, and Engage Energy, a joint venture of the Coastal Corporation and West Coast Energy, and its successor, El Paso Merchant Energy from September 1997 to May 2000. Mr. Wylie also held senior positions at Transocean Sedco Forex from June 1993 to September 1997.

Joshua L. Collins was elected to the Board of Directors in March 2005. Mr. Collins is a principal of LBMB and a Senior Vice President of Lehman Brothers. Mr. Collins Joined LBMB in 1996. Mr. Collins is currently a director of Blount International Inc.

David L. Lemmon was elected to our General Partner's Board of Directors in April 2002. Mr. Lemmon has served as President and Chief Executive Officer of Colonial Pipeline Company since November 1997 and as a director from 1990 to November 1997. He served as President of Amoco Pipeline Company from 1990 to 1997, as Manager for Corporate Planning for Amoco Corporation from 1989 to 1990 and Vice President and General Manager Operations for Amoco Pipeline Company from 1987 to 1989. Mr. Lemmon joined Amoco in 1965. Mr. Lemmon serves as chairman of the Audit Committee and is a member of the Compensation, Conflicts and Nominating and Governance Committees.

John C. Linehan was elected to our General Partner's Board of Directors in April 2004. Mr. Linehan served as the Chairman and Chief Executive Officer of Texaco Refining and Marketing (East) Inc. from September 2001 to March 2002. Prior thereto, from 1985 to 1999, Mr. Linehan held various positions at the Kerr-McGee Corporation, including Vice President, Controller, Executive Vice President and Chief Financial Officer. Mr. Linehan serves as Chairman of the Conflicts Committee and is a member of the Audit and Compensation Committees.

Douglas L. Polson was elected to our General Partner's Board of Directors in December 2001, serving as Chairman from December 2001 until March 2005. He was Chairman of the Board of Directors of Pacific Energy Group LLC from August 2001 to March 2005 and Chairman of the Members Committee of Pacific Pipeline System LLC from July 1999 to April 2002. Mr. Polson served as Vice President and a director of The Anschutz Corporation and Anschutz Company for more than five years until October 2002. Mr. Polson served on the boards of directors of Southern Pacific Rail Corporation from 1988 to 1996 and Qwest Communications International, Inc. from February 1997 to 2000.

Jim E. Shamas was elected to our General Partner's Board of Directors in December 2001. He served as a director of Pacific Energy Group LLC from August 2001 to March 2002 and as a representative on the Pacific Pipeline System LLC Members Committee from May 1999 to April 2002. From September 1994 until his retirement in December 1998, Mr. Shamas was President of Rooney Engineering, Inc. and Interwest Group, Inc. Mr. Shamas has served as a director of Rooney Engineering, Inc. since September 1994. Prior to that, he served as President and Chief Executive Officer of Texaco Trading and Transportation Inc. from August 1984 to August 1994. From May 1982 until August 1984, Mr. Shamas served as President and Chief Executive Officer of Getty Trading and Transportation and Vice President of Getty Oil Company. Mr. Shamas serves as Chairman of the Compensation Committee and is a member of the Audit, Conflicts and Nominating and Governance Committees.

William L. Thacker was elected to the Board of Directors in April 2004. From March 1997 until May 2002, Mr. Thacker held various positions at Texas Eastern Products Pipeline Co., LLC, the general partner of TEPPCO Partners, L.P., including serving as Chairman, President and Chief Executive Officer. Mr. Thacker serves as Chairman of the Nominating and Governance Committee and is a member of the Audit and Compensation Committees. Mr. Thacker serves on the Board of Directors of Copano Energy L.L.C.

Jeffrey C. Weber was elected to the Board of Directors in March 2005. Mr. Weber is a principal of LBMB and a Vice President of Lehman Brothers. Prior to joining LBMB in 2000, Mr. Weber was an aviation officer and Captain in the U.S. Army.

Irvin Toole, Jr. was elected President, Chief Executive Officer and director in December 2001. He has been President, Chief Executive Officer and director of Pacific Energy Group LLC since August 2001 and has been President and Chief Executive Officer of Pacific Pipeline System LLC since July 1999 and served as a representative to its Members Committee from July 1999 to April 2002. Mr. Toole served as President and Chief Executive Officer of the predecessor of Pacific Pipeline System LLC in June 1998 after having served as Chairman, President and Chief Executive Officer of Santa Fe Pacific Pipelines, Inc., the general partner of Santa Fe Pacific Pipeline Partners, L.P., from September 1991 to April 1998.

David E. Wright was elected Executive Vice President, Corporate Development in February 2005. He has been Executive Vice President, Corporate Development and Marketing since December 2001 and served as a director of Pacific Energy GP, Inc. from December 2001 to June 2002. He has been Executive Vice President, Corporate Development and Marketing and director of Pacific Energy Group LLC since August 2001 and Executive Vice President, Corporate Development and Marketing of Pacific Pipeline System LLC since June 2001. Mr. Wright joined Pacific Energy Group LLC in June 2001 after having served as Vice President, Distribution West of Tosco Refining Company from March 1997 to June 2001. From October 1995 to March 1997, Mr. Wright served as Vice President, Pipelines for GATX Terminals Corporation.

Gerald A. Tywoniuk was elected Senior Vice President, Chief Financial Officer and Treasurer in December 2002. Previously, he was Senior Vice President, Chief Financial Officer and a member of the Board of Directors of the general partner of MarkWest Energy Partners, L.P. from its initial public offering in May 2002 to November 2002. He also served as Senior Vice President and Chief Financial Officer with MarkWest Hydrocarbon, Inc. from December 2001, and as a director from March 2002, to November 2002. Prior to that, Mr. Tywoniuk was MarkWest Hydrocarbon's Vice President of Finance and Chief Financial Officer since April 1997.

Lynn T. Wood was elected Vice President, General Counsel and Secretary in March 2002. He has been Vice President of Pacific Energy Group LLC since August 2001, Vice President of Pacific Pipeline System LLC and its predecessor since October 1998 and Secretary since October 1996. Mr. Wood was the Secretary and Assistant General Counsel of Anschutz Company and The Anschutz Corporation from October 1996 to October 2002, during which time he had the responsibility for providing ongoing legal services to Pacific Pipeline System LLC and, after their formation, Pacific Energy Group LLC and the Partnership.

Arthur G. Diefenbach was elected Senior Vice President, West Coast Business Unit in February 2005. He has been Vice President, Operations & Technical Services of Pacific Energy Group LLC since August 2001 and Vice President, Operations & Technical Services of Pacific Pipeline Systems LLC since July 1999. Mr. Diefenbach joined Pacific Energy Group LLC in July 1999 after having served as Manager, Western Region of ARCO Pipeline Company from August 1998 to July 1999 and as Superintendent, Operations of ARCO Pipeline Company from January 1990 to August 1998.

Gary L. Zollinger was elected Senior Vice President, Rocky Mountain Business Unit in February 2005. He has been Vice President, Marketing and Business Development Rocky Mountains since March 2002. Mr. Zollinger joined Pacific Energy Group LLC in January 2002 after having served as President of Crossing Associates LLC from 2001 to January 2002. From 1998 to 2001, he served as

Vice President of North American Consulting Group LLC. Crossing Associates LLC and North American Consulting Group LLC are privately held consulting firms specializing in the midstream energy business. From 1997 to 1998, Mr. Zollinger did private consulting work in the mid-stream energy business.

Lyle B. Boarts was elected Vice President, Human Resources in January 2004. Before joining Pacific Energy GP, Inc., he was Vice President, Human Resources, GTran Inc. from March 2000 to August 2004 and was Vice President, Human Resources with Ortel Corporation from March 1998 to August 1999. Mr. Boarts also served as Vice President, Human Resources with Santa Fe Pacific Pipelines, Inc., general partner of Santa Fe Pacific Pipeline Partners, L.P., from June 1986 to March 1998.

The following table shows other officers of PEM as of March 4, 2005:

Name	**Age**	**Position with the General Partner**
Dominic D. Ferrari	51	Vice President, Corporate Development
John Kers	57	Vice President, Operations and Technical Services Canada
Jesse G. Metcalf	54	Vice President, Operations and Technical Services Rocky Mountains
Khalid A. Muslih	33	Vice President, Corporate Development
Edward L. Scheibelhut	45	Vice President, Marketing and Business Development Canada
John Tsouvalas	46	Vice President, Marketing and Business Development West Coast
Harsha M. Tank	42	Controller

Dominic D. Ferrari was elected Vice President, Corporate Development in August 2004. Mr. Ferrari has been with Pacific Energy since 2001, serving most recently as Senior Director, Corporate Development. Prior to joining Pacific Energy, Mr. Ferrari was with Unocal Pipeline Company from 1975 to 2001. While at Unocal, he held various positions including Vice President and Manager of Joint Ventures, Project Manager SPR Project, and Coordinator Joint Ventures.

John Kers was elected Vice President, Operations and Technical Services Canada in August 2004. He previously served as Director and Vice President, Operations Engineering and Construction for Plains Marketing Canada, L.P. from 2001 to 2004. Prior to joining Plains, Mr. Kers served in progressive managerial assignments at Murphy Oil Company, Ltd from 1980 to 2001, including Manager of Engineering.

Jesse G. Metcalf was elected Vice President, Operations and Technical Services Rocky Mountains in March 2002. From 2000 to March 2002, Mr. Metcalf served as Vice President, Anschutz Ranch East Pipeline, Anschutz Marketing and Transportation and Anschutz Wahsatch Gathering System. Prior to that, he served as Manager, Operations for Anschutz Ranch East Pipeline, Anschutz Marketing and Transportation and Anschutz Wahsatch Gathering System from 1987 to 2000. From 1982 to 1987, Mr. Metcalf served as Field Supervisor, Exploration and Production for The Anschutz Corporation.

Khalid A. Muslih was elected Vice President Corporate Development in March 2005. Mr. Muslih previously served as Commercial Officer, Mergers & Acquisitions of NuCoastal Corporation since July 2002. Prior to NuCoastal Corporation, Mr. Muslih served as Director, Merchant & International Regulatory Affairs with El Paso Corporation from January 2001 to June 2002 and as Director, Legislative and Regulatory Affairs for The Coastal Corporation from January 1999 to December 2000. From July 1994 to December 1998, Mr. Muslih held various positions with Coastal States Refining and Marketing, Inc. and at Coastal States Management Corporation from June 1993 to June 1994.

Edward L. Scheibelhut was elected Vice President of Marketing and Business Development Canada in May 2004. Mr. Scheibelhut previously served as Manager, Strategic Implementation of BP Canada Energy Company from October 2002 to May 2004 and Manager of Marketing and Trading from January 2000 to October 2002. Mr. Scheibelhut served as Manager, Business Development and Planning of BP Canada Energy Company from December 1998 to January 2000.

John Tsouvalas was elected Vice President, Marketing and Business Development West Coast in October 2003. He has been the Director, Marketing and Business Development for Pacific Energy Group LLC's West Coast Operations from August 2001 to October 2003 and Director of Marketing and Business Development of Pacific Pipeline System LLC from July 1999 to August 2001. Mr. Tsouvalas joined Pacific Energy Group LLC in July 1999 after having served as West Coast Crude Asset Manager for ARCO Pipe Line Company from January 1996 to July 1999 and as Marketing and Scheduling Manager of ARCO Pipe Line Company West Coast from January 1990 to January 1996.

Harsha M. Tank was elected Controller in April 2003. She joined Pacific Energy GP, Inc. as Manager, Internal Audit and Performance Analysis in September 2002. Prior to joining Pacific Energy GP, Inc., Ms. Tank served as Controller for James Hardie Building Products, Inc. in 2002 and as Regional Controller for Qwest Digital Media LLC from 2000 to 2002. Ms. Tank also served as Regional Controller for Mail-Well, Inc. for their Southwest Region from 1996 to 2000.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires directors, officers and persons who beneficially own 10% or more of a class of our equity securities that is registered under Section 12 of the Exchange Act to file with the SEC and the New York Stock Exchange initial reports of ownership and reports of changes in ownership of such securities. These persons are also required to furnish us copies of all of the Section 16(a) reports they filed. Based solely upon a review of the copies of reports on Forms 3, 4 and 5 furnished to us, or written representations that no reports on Form 5 were required, we believe the directors and officers of our General Partner, and our General Partner in its capacity as a beneficial owner complied with all filing requirements with respect to transactions in our equity securities in 2004.

Committees and Meetings

The Board of Directors has the responsibility for establishing broad policies and for our overall direction and management. The Board of Directors held four regular meetings and five special meetings during 2004. A director was absent from one of the regular meetings and another director was absent from one of the special meetings, otherwise all directors attended all meetings. The Board has established standing committees to consider designated matters. The standing committees of the Board are Audit, Compensation, Conflicts, and Nominating and Governance.

Audit Committee

The members of the Audit Committee are: David L. Lemmon, Chairman, Jim E. Shamas, John C. Linehan and William L. Thacker. The members of the Audit Committee are not officers or employees of our General Partner. Among other things, the Audit Committee is responsible for reviewing our external financial reporting, including reports filed with the SEC, engaging and reviewing our independent auditors, and reviewing procedures for internal auditing and the adequacy of our internal accounting controls. The Committee held five meetings during 2004, and all members of the Committee attended each such meeting.

The Board of Directors has determined that all of the members of the Audit Committee are "audit committee financial experts," as that term is defined under the Securities Act and the Exchange Act, and that each is "independent," as that term is used in the Exchange Act.

Compensation Committee

The members of the Compensation Committee are: Jim E. Shamas, Chairman, David L. Lemmon, John C. Linehan, Christopher R. Manning and William L. Thacker. The Compensation Committee is responsible for overseeing compensation related decisions for the directors, officers and employees of our General Partner. The committee held four meetings during 2004, and all members of the Committee attended each such meeting.

Conflicts Committee

The members of the Conflicts Committee are: John C. Linehan, Chairman, David L. Lemmon and Jim E. Shamas. The Conflicts Committee is responsible for reviewing specific matters, including those that the Board of Directors believes may involve conflicts of interest between our General Partner or its affiliates and the Partnership. The General Partner is authorized, but not required, to seek approval of the Conflicts Committee whether the resolution of a conflict of interest is fair and reasonable to us. The members of the Conflicts Committee are not officers or employees of our General Partner or its affiliates. The Committee held two meetings during 2004, which were attended by all members of the Committee.

Nominating and Governance Committee

The members of the Nominating and Governance Committee are: William L. Thacker, Chairman, Douglas L. Polson, David L. Lemmon, Christopher R. Manning and Jim E. Shamas. The Nominating and Governance Committee is responsible for assisting the Board of Directors in identifying individuals qualified to become Board members, recommending nominees to Board committees, formulating and recommending guidelines for corporate governance, and leading the Board in its annual review of the Board's performance. The Committee held four meetings in 2004, which were attended by all members.

Code of Ethics

Our General Partner has adopted a code of ethics that applies to all employees, including its principal executive officers, principal financial officer, principal accounting officer and its Board of Directors. A copy of the code of ethics is available on our Internet website at www.PacificEnergy.com. Our General Partner intends to satisfy the disclosure requirement under Item 10 of the current report on Form 8-K regarding an amendment to, or a waiver from, a provision of its code of ethics by posting such information on our website at the Internet website address set forth above.

Reimbursement of Expenses of the General Partner

Our General Partner does not receive any management fee or other compensation for its management of the Partnership. However, our General Partner and its affiliates are reimbursed for all expenses incurred by them on our behalf. These expenses include the costs of employee, officer and director compensation and benefits properly allocable to us and all other expenses necessary or appropriate to the conduct of our business. The partnership agreement provides that our General Partner may determine the expenses that are allocable to us in any reasonable manner determined by our General Partner in its sole discretion.

Executive Sessions

The Board of Directors will have an executive session for the non-management directors on a regular basis without management present. If the non-management directors include any directors who are not independent directors, then the independent directors will meet in separate executive session without the other directors or management at least once each year to discuss such matters as the independent directors consider appropriate. A majority of the independent directors will select a presiding director for these executive sessions. In addition, any director may call for an executive session of non-management or independent directors at any Board of Directors meeting.

Communications from Unitholders, Employees and Others

Unitholders, employees and other interested persons who wish to communicate with the Board of Directors, non-management directors as a group, a committee of the Board of Directors or a specific director may do so by letters so addressed to the care of our corporate secretary. Letters addressed to the Board of Directors in general will be reviewed by the corporate secretary and relayed to the Chairman of the Board of Directors or the chair of an appropriate committee. Letters addressed to the non-management directors in general will be relayed unopened to the chair of the Audit Committee. Letters addressed to a committee of the Board of Directors or a specific director will be relayed unopened to the chair of the committee or the specific director to whom they are addressed. All letters regarding accounting, accounting policies, internal accounting controls and procedures, auditing matters, financial reporting processes, or disclosure controls and procedures shall be forwarded by the recipient director to the chair of the Audit Committee.

ITEM 11. Executive Compensation

We were formed in 2002. Officers and employees of our General Partner may participate in employee benefit plans and arrangements sponsored by our General Partner, including plans that may be established by our General Partner in the future.

The following table sets forth certain information with respect to compensation of our General Partner's chief executive officer and certain other executive officers.

SUMMARY COMPENSATION TABLE

	Annual Compensation				Long-term Compensation		
Name and Principal Position	**Year**	**Salary**	**Bonus**	**Other Annual Compensation(4)**	**Unit Option Grants Awards**	**LTIP Payouts(5)**	**All Other Compensation(6)**
Douglas L. Polson(1)	2004	$ 293,333	$ 199,287	$		$ 2,087,250	$ 24,600
Chairman of the Board	2003	280,000	112,042			1,962,000	24,033
of Directors	2002	243,883	200,760		50,000		22,823
Irvin Toole, Jr.	2004	273,333	184,470			696,000	12,300
President, Chief	2003	260,000	104,657			678,500	12,050
Executive Officer and	2002	260,000	191,158				12,305
Director							
David E. Wright	2004	214,000	123,567			208,800	12,300
Executive Vice	2003	206,500	57,903			203,625	5,679
President, Corporate	2002	204,875	122,585				6,306
Development							
Gerald A.	2004	205,625	79,924			55,680	12,300
Tywoniuk(2)	2003	200,000	44,725	88,171		54,300	9,000
Senior Vice President,	2002	16,667	6,639				51,000
Chief Financial							
Officer and Treasurer							
Lynn T. Wood(3)	2004	174,500	67,390			139,200	14,385
Vice President,	2003	170,000	35,721	167,322		135,750	8,075
General Counsel and	2002	156,278	62,864				13,379
Secretary							

(1) Prior to October 1, 2002, Douglas L. Polson was employed by The Anschutz Corporation and acted as an executive officer of our General Partner. The 2002 salary and other compensation amounts shown include $194,748 and $20,400, respectively, paid by The Anschutz Corporation to Mr. Polson for time spent on Partnership related matters, which is estimated at 85% of Mr. Polson's services for the period of January 1 through October 1, 2002.

(2) Gerald A. Tywoniuk became an employee of our General Partner on December 2, 2002.

(3) Prior to September 16, 2002, Lynn T. Wood was employed by The Anschutz Corporation and acted as an executive officer of our General Partner. The 2002 salary and other compensation amounts shown include $107,348 and $10,157, respectively, paid by The Anschutz Corporation to Mr. Wood for time spent on Partnership related matters.

(4) Includes, for Mr. Tywoniuk and Mr. Wood, reimbursement of relocation expenses, including reimbursement of associated income taxes of $33,027 and $64,612, respectively.

(5) Calculated as follows: common units issued upon vesting (pursuant to our long-term incentive plan), multiplied by the closing market price on the day prior to issuance.

In connection with the LB Acquisition on March 3, 2005, restricted units outstanding under our long-term incentive plan and held by the individuals named in the table vested as follows:

Name	Number of Units
Douglas L. Polson	
Irvin Toole, Jr.	25,000
David E. Wright	22,500
Gerald A. Tywoniuk	11,000
Lynn T. Wood	15,000

(6)

Reflects employer contribution to our General Partner's 401(k) plan, and in the case of Mr. Tywoniuk, a one-time payment of $50,000 in 2002 upon commencement of employment with our General Partner.

Long-Term Incentive Plan Awards

No common unit options were granted in 2004. No restricted units were granted in 2004 to the individuals named in the Summary Compensation Table above.

Compensation of Directors

Beginning May 2003, our General Partner increased the annual rate of compensation for outside directors to $40,000, which covers attendance at meetings of the Board of Directors as well as committee meetings and serving as committee chairman. The previous annual compensation was $30,000. Our General Partner paid no director's fee to directors who were also officers or employees of The Anschutz Corporation or our General Partner. In 2003, outside directors also each received a grant of 3,000 restricted units under our long-term incentive plan, which were to vest over three years. In 2004, two new outside directors each received a grant of 2,000 restricted units under our long-term incentive plan, which were to vest over two years. In addition, each director is reimbursed for his out-of-pocket expenses in connection with attending meetings of the Board of Directors or committees. Each director will be fully indemnified by us for his actions associated with being a director to the fullest extent permitted under Delaware law.

Employment Agreements

Douglas L. Polson

Mr. Polson entered into an employment agreement with our General Partner effective on October 1, 2002. The employment agreement provided for an annual base salary and an annual bonus in accordance with our General Partner's annual incentive plan. Mr. Polson was also eligible to participate in all other bonus and benefit programs for which employees and/or senior executives are generally eligible. In addition, he was reimbursed for reasonable expenses incurred in his capacity as Chairman of the Board of Directors.

On March 3, 2005, Mr. Polson entered into a Special Agreement and a Consulting Agreement with PEM, and, in consideration thereof, Mr. Polson executed a general release. Pursuant to the Special Agreement, PEM assumed the rights and obligations of our General Partner under Mr. Polson's employment agreement, and, pursuant to the general release, Mr. Polson released PEM and its affiliates, including the Partnership, from claims which Mr. Polson has or may have against them, including under Mr. Polson's employment agreement. In accordance with the Special Agreement, Mr. Polson resigned as Chairman of the Board of Directors our General Partner effective March 3, 2005. Pursuant to the Special Agreement, on or around March 8, 2005, Mr. Polson was paid approximately $934,673, representing accrued but unused vacation, accrued salary through March 3, 2005 and payment in satisfaction of other obligations under the Employment Agreement. Mr. Polson is also entitled under the Special Agreement to certain medical reimbursement and dental and life insurance benefits, and office related services, for varying periods after the effective date of the agreement. Pursuant to the Ancillary Agreement, LBP reimbursed PEM for the severance portion of the amounts being paid to Mr. Polson, which amounted to more than $900,000 of the total. Mr. Polson now serves as a non-executive member of the Board of Directors of PEM. Pursuant to the Consulting Agreement, Mr. Polson has agreed to perform advisory services to PEM as shall be mutually agreed between Mr. Polson and the Chief Executive Officer of PEM from time to time. In consideration for Mr. Polson's services under the Consulting Agreement, which has a one-year term, Mr. Polson will receive a monthly consulting fee of $12,500 and reimbursement of all reasonable business expenses incurred or paid by Mr. Polson in the course of performing his duties thereunder.

Irvin Toole, Jr.

Mr. Toole entered into an employment agreement with our General Partner on January 1, 2002. The employment agreement provides for an annual base salary and an annual bonus in accordance with our General Partner's annual incentive plan. Mr. Toole is also eligible to participate in all other bonus and benefit programs for which employees and/or senior executives are generally eligible. In addition, he will be reimbursed for reasonable expenses incurred in his capacity as President and Chief Executive Officer and will be provided with a vehicle.

Under his employment agreement, our General Partner may terminate Mr. Toole's employment for cause or without cause. If Mr. Toole's employment is terminated without cause, he will, among other things, be entitled to a one-time severance payment as well as continuation of certain benefits for up to two years. If Mr. Toole is terminated without cause following a change of control or as a result of corporate downsizing, or if he resigns for "good reason," as defined in the agreement, following a change of control, he will then be entitled to substantially the same severance benefits as if he had been terminated without cause, except that the amount of the one-time severance payment will increase.

Mr. Toole's employment agreement also contains indemnification, non-solicitation and non-disclosure provisions.

David E. Wright

Mr. Wright entered into an employment agreement with our General Partner on January 1, 2002. The employment agreement provides for an annual base salary and an annual bonus in accordance with our General Partner's annual incentive plan. Mr. Wright is also eligible to participate in all other bonus and benefit programs for which employees and/or senior executives are generally eligible. In addition, he will be reimbursed for reasonable expenses incurred in his capacity as Executive Vice President, Corporate Development and Marketing and will be provided with a vehicle.

Under his employment agreement, our General Partner may terminate Mr. Wright's employment for cause or without cause. If Mr. Wright's employment is terminated without cause, he will, among other things, be entitled to a one-time severance payment. If Mr. Wright is terminated without cause following a change of control or as a result of corporate downsizing, or if he resigns for "good reason," as defined in the agreement, following a change of control, he will then be entitled to substantially the same severance benefits as if he had been terminated without cause, except that the amount of the one-time severance payment will increase, certain of his benefits will continue for up to two years and he will be entitled to receive six months of executive outplacement services.

Mr. Wright's employment agreement also contains indemnification, non-solicitation and non-disclosure provisions.

Gerald A. Tywoniuk

Mr. Tywoniuk entered into an employment agreement with our General Partner effective on November 1, 2002. The employment agreement provides for an annual base salary and an annual bonus in accordance with our General Partner's annual incentive plan. Mr. Tywoniuk is also eligible to participate in all other bonus and benefit programs for which employees and/or senior executives are generally eligible. In addition, he will be reimbursed for reasonable expenses incurred in his capacity as Chief Financial Officer and will be provided with a vehicle. Upon commencement of his employment, Mr. Tywoniuk received a one-time payment.

Under his employment agreement, our General Partner may terminate Mr. Tywoniuk's employment for cause or without cause. If Mr. Tywoniuk's employment is terminated without cause, he will, among other things, be entitled to a one-time severance payment. If Mr. Tywoniuk is terminated without cause following a change of control or as a result of corporate downsizing, or if he resigns for "good reason," as defined in the agreement, following a change of control, he will then be entitled to substantially the same severance benefits as if he had been terminated without cause, except that the amount of the one-time severance payment will increase, certain of his benefits will continue for up to one year and he will be entitled to receive three months of executive outplacement services.

Mr. Tywoniuk's employment agreement also contains indemnification, non-solicitation and non-disclosure provisions.

Lynn T. Wood

Mr. Wood entered into an employment agreement with our General Partner effective on September 5, 2002. The employment agreement provides for an annual base salary and an annual bonus in accordance with our General Partner's annual incentive plan. Mr. Wood is also eligible to participate in all other bonus and benefit programs for which employees and/or senior executives are generally eligible. In addition, he will be reimbursed for reasonable expenses incurred in his capacity as Vice President, General Counsel and Secretary and will be provided with a vehicle.

Under his employment agreement, our General Partner may terminate Mr. Wood's employment for cause or without cause. If Mr. Wood's employment is terminated without cause, he will, among other things, be entitled to a one-time severance payment. If Mr. Wood is terminated without cause following a change of control or as a result of corporate downsizing, or if he resigns for "good reason," as defined in the agreement, following a change of control, he will then be entitled to substantially the same severance benefits as if he had been terminated without cause, except that the amount of the one-time severance payment will increase, certain of his benefits will continue for up to one year and he will be entitled to receive three months of executive outplacement services.

Mr. Wood's employment agreement also contains indemnification, non-solicitation and non-disclosure provisions.

Gary L. Zollinger

Mr. Zollinger entered into an employment agreement with our General Partner on January 1, 2002. The employment agreement provides for an annual base salary and an annual bonus in accordance with our General Partner's annual incentive plan. Mr. Zollinger is also eligible to participate in all other bonus and benefit programs for which employees and/or senior executives are generally eligible. In addition, he will be reimbursed for reasonable expenses incurred in his capacity as Vice President, Marketing and Business Development Rocky Mountain Operations.

Under his employment agreement, our General Partner may terminate Mr. Zollinger's employment for cause or without cause. If Mr. Zollinger's employment is terminated without cause, he will, among other things, be entitled to a one-time severance payment. If Mr. Zollinger is terminated without cause following a change of control or as a result of corporate downsizing, or if he resigns for "good reason," as defined in the agreement, following a change of control he will then be entitled to substantially the same severance benefits as if he had been terminated without cause, except that the amount of the one-time severance payment will increase, certain of his benefits will continue for up to one year and he will be entitled to receive three months of executive outplacement services.

Mr. Zollinger's employment agreement also contains indemnification, non-solicitation and non-disclosure provisions.

Long-Term Incentive Plan

General

Our General Partner has adopted a long-term incentive plan for employees and directors of the General Partner and employees of its affiliates who perform services for us.

The plan consists of two components: restricted units and unit options. The aggregate number of units permitted to be granted under the long-term incentive plan is 1,750,000. The long-term incentive plan is administered by the Compensation Committee of the Board of Directors, subject to the approval of Compensation Committee recommendations by the Board of Directors. Grant levels, the type of award and the frequency of grants for designated employees will be recommended by the chairman and by the chief executive officer of our General Partner, subject to the review and approval of the Compensation Committee. The Compensation Committee will determine the grant level, the type of award and the frequency of grants for directors. The Board of Directors may terminate or amend the plan at any time with respect to units for which a grant has not yet been made. However, no change may be made that would materially impair the rights of a participant with respect to an outstanding grant without the consent of the participant.

Upon vesting of restricted units or the exercise of unit options, the Partnership has the option of paying the holder of the restricted units or the options in cash equal to the fair market value, by issuing common units acquired by our General Partner in the open market, common units already owned by our General Partner, common units acquired by our General Partner directly from us or any other person, new common units issued by us, or any combination of the foregoing. As restricted units vest, we intend to deliver common units rather than pay cash. Our General Partner will be entitled to reimbursement by us for the cost incurred in acquiring common units. If we issue new common units upon vesting of the restricted units, or the exercise of a unit option, the total number of common units outstanding will increase.

Restricted Units

A restricted unit is a "phantom" unit. A phantom unit entitles the grantee to receive a common unit upon the vesting of the phantom unit or, in the discretion of the Compensation Committee, cash equivalent to the value of a common unit. In 2002, we granted 381,250 restricted units of which 12,500 were subsequently forfeited. In 2003, our General Partner granted 25,000 and 9,000 restricted units to its employees and three outside directors, respectively. Of the units granted in 2003, 3,000 units were subsequently forfeited. In January 2004, our General Partner granted an additional 7,500 restricted units to an employee and effective in April 2004, an additional 2,000 restricted units to each of two new outside directors. In the future, the Compensation Committee may determine to make additional grants under the plan to employees and directors containing such terms as the Compensation Committee shall determine under the plan. The Compensation Committee will determine the period over which restricted units granted to employees and directors will vest. The committee may base its determination upon the achievement of specified financial objectives. If a grantee's employment or membership on the Board of Directors terminates for any reason other than death, disability or upon the occurrence of certain other specified events that cause immediate full vesting, the grantee's unvested restricted units will be automatically forfeited unless, and to the extent, the Compensation Committee provides otherwise. In addition, the restricted units will vest upon a change of control of Pacific Energy Partners or our General Partner. The Compensation Committee, in its discretion, may grant tandem distribution equivalent rights, i.e. the right to receive cash equal to cash distributions made on a common unit, with respect to restricted units; however, none have been granted.

We intend the issuance of the restricted units under the plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, plan participants will not pay any consideration for the common units they receive, and we will receive no remuneration for such units.

In connection with the closing of the LB Acquisition on March 3, 2005, all 144,750 restricted units outstanding under our long-term incentive plan vested.

The Compensation Committee may determine to grant unit options under the plan to employees and directors containing such terms as the committee shall determine. Unit options will have an exercise price that may not be less than the fair market value of the units on the date of grant. In general, unit options granted will become exercisable over a period determined by the Compensation Committee. In addition, the unit options will become exercisable upon a change in control of Pacific Energy Partners or our General Partner. The unit option plan has been designed to furnish additional compensation to employees and directors and to align their economic interests with those of common unitholders. No unit options were granted in 2004 and 2003. In December 2002, we granted 50,000 unit options.

Annual Incentive Plan

Our General Partner has an annual incentive compensation plan that is designed to enhance the performance of eligible employees of our General Partner by rewarding them with cash awards for certain individual achievements and the Partnership achieving certain annual financial and operational performance objectives. The Compensation Committee may in its discretion determine individual participants and payments, if any, for each fiscal year. The Board of Directors may amend or change the annual incentive plan at any time. We reimburse our General Partner for payments and costs incurred under the plan.

ITEM 12. Security Ownership of Certain Beneficial Owners and Management

The following table sets forth the beneficial ownership of equity securities of Pacific Energy Partners as of March 4, 2005, held by beneficial owners of more than 5% of the units, by directors of our General Partner, by each named executive officer and by all directors and executive officers of our General Partner as a group.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned(3)	Subordinated Units Beneficially Owned(4)	Percentage of Subordinated Units Beneficially Owned	Percentage of Total Equity Beneficially Owned(3)
Lehman Brothers Holdings, Inc.(1)			10,465,000(5)	100%(6)	34.5%(6)
LB Pacific, LP(1)			10,465,000	100%	34.5%
Pacific Energy GP, LP(2)					*
Douglas L. Polson	104,380	*			*
Forrest E. Wylie		*			*
Christopher R. Manning		*	10,465,000(5)	100%(6)	34.5%(6)
Joshua L. Collins		*	10,465,000(5)	100%(6)	34.5%(6)
Jeffrey C. Weber		*	10,465,000(5)	100%(6)	34.5%(6)
David L. Lemmon	3,100	*			*
John C. Linehan	2,500	*			*
Jim E. Shamas	4,000	*			*
William L. Thacker.	2,000	*			*
Irvin Toole, Jr.	50,186	*			*
David E. Wright	28,575	*			*
Gerald A. Tywoniuk	12,139	*			*
Lynn T. Wood	17,061	*			*
All directors and executive officers as a group (16 persons)	249,718	1.3%	10,465,000	100%	35.3%

(1) The address of each of Lehman Brothers Holdings, Inc. and LB Pacific, LP is 399 Park Avenue, New York, NY 10022.

(2) The address of Pacific Energy GP, LP is 5900 Cherry Avenue, Long Beach, California, 90805-4408.

(3) In each instance a "*" indicates that the individual owns less than 1.0% of the common and total units outstanding.

(4) The subordinated units are convertible on a one-to-one basis into common units upon the satisfaction of certain financial tests set forth in our limited partnership agreement.

(5) The subordinated units shown as beneficially owned by Lehman Brothers Holdings, Inc., Christopher R. Manning, Joshua L. Collins and Jeffrey C. Weber are directly owned by LB Pacific, LP. Lehman Brothers Holdings, Inc. controls LBMB, which controls LB Pacific, LP, and thus may be deemed to have beneficial ownership of the subordinated units owned by LB Pacific, LP. Messrs. Manning, Collins and Weber are members of the board of managers of the general partner of LB Pacific, LP and may be deemed to share beneficial ownership of the subordinated units shown as beneficially owned by LB Pacific, LP. Messrs. Manning, Collins and Weber disclaim beneficial ownership of all such shares.

(6) See Footnote (5) with respect to subordinated units which may be attributable to Lehman Brothers Holdings, Inc. and Messrs. Manning, Collins and Webber that have been included in the total. Messrs. Manning, Collins and Weber disclaim beneficial ownership of all such shares.

Immediately after the closing of the LB Acquisition on March 3, 2005, restricted units under our long-term incentive plan vested. As a result, the LB Pacific, LP interest decreased from 34.6% to 34.5%.

Changes in Control

LBP financed a portion of the purchase price it paid in the LB Acquisition with the proceeds from a $175.0 million secured credit and guarantee agreement (the "Credit Agreement"), entered into at the closing of the LB Acquisition by and among LBP, as borrower, the several lenders parties thereto, Citicorp North America, Inc., as administrative agent and collateral agent and Lehman Commercial Paper Inc., as syndication agent, and Citigroup Global Markets Inc. as sole lead arranger and sole bookrunner. We are not a party to the Credit Agreement. The Credit Agreement is secured by a pledge of substantially all of the assets of LBP, including the interest of LBP in PEM and our General Partner. If LBP defaults on its obligations under the Credit Agreement the lenders could exercise their rights under this pledge, which could result in a future change of control of us.

Equity Compensation Plan Information

The following table sets forth certain information at December 31, 2004 with respect to the number of units issuable under our equity compensation plans:

Plan Category	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options	(b) Weighted Average Exercise Price of Outstanding Options	(c) Number of Securities Remaining Available For Future Issuance Under Equity Compensation Plans (excluding securities reflected in column a)
Equity Compensation Plans Approved By Unitholders			
Equity Compensation Plans Not Approved By Unitholders	50,000	$ 19.50	1,516,253

For a description of the material features of our long-term incentive plan and annual incentive plan, please see "Item 11 Long-Term Incentive Plan" and "Item 11 Annual Incentive Plan" above.

ITEM 13. Certain Relationships and Related Transactions

Distributions and Payments to the General Partner and its Affiliates

The following table summarizes the distributions and payments to be made by us to our General Partner and its affiliates in connection with the ongoing operation and any liquidation of Pacific Energy Partners, L.P. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm's-length negotiations.

Operational Stage
(Subsequent to July 26, 2002)

Distributions of available cash to our General Partner	We will generally make cash distributions 98% to the unitholders, including LBP as holder of all of the subordinated units, and 2% to our General Partner. In addition, if distributions exceed the minimum quarterly distribution and other higher target levels, our General Partner, as the holder of the incentive distribution rights, will be entitled to increasing percentages of the distributions, up to 48% of the distributions above the highest target level.
	Assuming we have sufficient available cash to pay the full minimum quarterly distribution on all of our outstanding units for four quarters, our General Partner would receive aggregate distributions for the four quarters of approximately \$1.1 million on the General Partner's 2% general partner interest and LBP would receive approximately \$19.4 million on its subordinated units.
Reimbursements to our General Partner and its affiliates	Our General Partner, including its general partner, Pacific Energy Management LLC, will be entitled to reimbursement for all expenses it incurs on our behalf, including salaries and employee benefit costs for its employees who provide services to us, and all other necessary or appropriate expenses allocable to us or reasonably incurred by our General Partner in connection with operating our business. Our General Partner has sole discretion in determining the amount of these expenses.
Withdrawal or removal of our General Partner	If our General Partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.

Liquidation Stage

Liquidation	Upon our liquidation, the partners, including our General Partner, will be entitled to receive liquidating distributions according to their particular capital account balances.

Omnibus Agreement

In connection with the completion of our initial public offering in July 2002, we entered into an omnibus agreement with TAC and our General Partner that addressed the following matters:

(1) TAC and its affiliates' agreement not to compete with us under certain circumstances; and

(2) an indemnity by TAC for certain environmental liabilities and income tax liabilities.

In connection with the LB Acquisition, the omnibus agreement was amended. The amendment eliminated the non-compete provisions that TAC and its affiliates had agreed to, but retained the indemnity by TAC for certain environmental liabilities and income tax liabilities.

Indemnification

Pursuant to the omnibus agreement, TAC has agreed to indemnify us for three years following the completion of our initial public offering against unknown environmental liabilities associated with the operation of the assets contributed to us by TAC and occurring before July 26, 2002. This indemnity is limited to a maximum of $10.0 million and is subject to a $1.0 million aggregate deductible.

TAC also agreed to indemnify us for certain income tax liabilities attributable to the operation of the assets contributed to us prior to the time that they were contributed.

Ancillary Agreement

On October 29, 2004, we entered into an Ancillary Agreement with PPS Holding Company, LBP, TAC and our General Partner. Pursuant to this agreement, the following terms, among others, were agreed to:

- TAC agreed to enter into a transition services agreement with us;
- TAC, PPS Holding and their affiliates agreed not to compete with us under certain circumstances; and
- LBP agreed not to compete with us under certain circumstances.

In addition, LBP agreed to reimburse us or our affiliates for certain severance costs resulting from the LB Acquisition and LBP, TAC and one of TAC's affiliates agreed to reimburse certain specified types of costs of the Partnership relating to the LB Acquisition, including legal fees and accounting fees, up to an aggregate of $650,000, and certain other specified types of costs, without a limitation on the amount of reimbursement.

On or around March 8, 2005, pursuant to the terms of the Ancillary Agreement, LBP reimbursed PEM for more than $900,000, which PEM paid to Douglas L. Polson under the Special Agreement between PEM and Mr. Polson. For more information on the Special Agreements and other transactions with Mr. Polson, see "Cost Reimbursements" below.

Other Related Party Transactions

In the ordinary course of our operations, we engaged in various transactions with TAC and its affiliates. These transactions, which are more thoroughly described below, are summarized in the following table for the year ended December 31, 2004, 2003 and 2002:

	For the Year Ended December 31,		
	2004	2003	2002
	(in thousands)		
Pipeline transportation revenue:			
TAC and affiliates	$ 528	$ 1,120	$ 2,682
Frontier Pipeline Company	880	575	479
Operating expenses:			
TAC and affiliates			496
General and administrative expense:			
TAC and affiliates	316	169	205

Related party balances at December 31, 2004 and 2003 are reflected on the consolidated balance sheets included in the section entitled "Item 8 Financial Statements and Supplementary Data" as follows:

	December 31,	
	2004	2003
	(in thousands)	
Amounts included in accounts receivable:		
TAC and affiliates	$ 224	$ 155
Frontier Pipeline Company	257	
	$ 481	$ 155
Amounts included in due to related parties:		
Due to Pacific Energy GP, Inc. (predecessor to Pacific Energy GP, LP)	$ 533	$ 580

Revenue from Related Parties

A subsidiary of TAC was a shipper on Line 2000 and was charged the published tariff rates applicable to "participating shippers" until March 31, 2003, when an agreement between the TAC subsidiary and a third party, the performance of which required the TAC subsidiary to ship on Line 2000, was assigned to us for consideration equal to the value of transferred inventory. The agreement ended April 1, 2003. In addition, a subsidiary of TAC is a shipper on pipelines owned by RMPS and is charged published tariff rates.

RMPS serves as the contract operator for certain gas producing properties owned by a subsidiary of TAC in Wyoming and Utah, in exchange for which RMPS is reimbursed its direct costs of operation and is paid an annual fee of $0.3 million as compensation for the time spent by RMPS management and for other overhead services related to their activities. In addition, during 2003 and the first half of 2004, RMPS's trucking operation hauled water for a TAC subsidiary at rates equivalent to those charged to third parties.

RMPS also receives a management fee from Frontier in connection with time spent by RMPS management and for other services related to Frontier's pipeline's activities. RMPS received $0.9 million, $0.6 million and $0.5 million for the years ended December 31, 2004, 2003 and 2002, respectively.

Expenses Paid to Related Parties

Operating Expense: Prior to April 1, 2002, TAC employed various personnel who worked directly on the AREPI pipeline, which is now part of our Salt Lake City Core system, and provided other executive, accounting and administrative support to AREPI. Most of these employees continue to provide services to the AREPI pipeline, but are now employed by our General Partner.

General and Administrative Expense: In 2002, we began utilizing the financial accounting system owned and provided by TAC under a shared services arrangement. In addition, from time to time until mid-2003 we utilized the services of TAC's risk management personnel for acquiring our insurance, and until 2004 our surety bonds were issued under TAC's bonding line. Beginning January 2003, TAC began charging us a fee of $0.1 million per year for these services and continues to charge us for any out-of-pocket costs it incurs. The fixed annual fee includes all license, maintenance and employee costs associated with our use of the financial accounting system. We will continue use of the financial accounting system after the close of the LB Acquisition pursuant to a transition services agreement until December 31, 2005.

In January 2003, we began leasing approximately 4,700 square feet of office space from an affiliate of TAC, for a term of five years at an initial annual cost of $0.1 million. This space was increased to 5,400 square feet in 2004.

Cost Reimbursements: Our General Partner employs all U.S.-based employees. All employee expenses incurred by the General Partner on our behalf are charged back to us.

The operating and general and administrative cost reimbursement amounts above exclude reimbursements for property, casualty and directors and officers' insurance premiums paid by TAC on our behalf, until mid-2003. Beginning with the 2003-2004 insurance policy period, we incurred these costs directly. In addition, out-of-pocket costs incurred by TAC for our benefit for computer consultants and surety bonds are also reimbursed by us.

Prior to our initial public offering in July 2002, TAC was providing letters of credit for PMT activities. PMT reimbursed TAC for its cost of providing these letters of credit. Following our initial public offering, such letters of credit were replaced by letters of credit under our $200.0 million revolving U.S. credit facility.

On March 3, 2005, Douglas L. Polson, previously the Executive Chairman of the Board of Directors of our General Partner, entered into a Special Agreement and a Consulting Agreement with PEM. Pursuant to the Special Agreement, PEM assumed the rights and obligations of our General Partner under that certain Employment Agreement, dated October 1, 2002, between Mr. Polson and our General Partner. In accordance with the Special Agreement, Mr. Polson resigned as Chairman of the Board of Directors our General Partner effective March 3, 2005. Pursuant to the Special Agreement, on or around March 8, 2005, Mr. Polson was paid approximately $934,673, representing accrued but unused vacation, accrued salary through March 3, 2005 and payment in satisfaction of other obligations under the Employment Agreement. Mr. Polson is also entitled under the Special Agreement to certain medical reimbursement and dental and life insurance benefits, and office related services, for varying periods after the effective date of the agreement. Pursuant to the Ancillary Agreement, LBP reimbursed PEM for the severance portion of the amounts being paid to Mr. Polson, which amounted to more than $900,000 of the total. Mr. Polson now serves as a non-executive member of the Board of Directors of PEM. Pursuant to the Consulting Agreement, Mr. Polson has agreed to perform advisory services to PEM as shall be mutually agreed between Mr. Polson and the Chief Executive Officer of PEM from time to time. In consideration for Mr. Polson's services under the Consulting Agreement, which has a one-year term, Mr. Polson will receive a monthly consulting fee of $12,500 and reimbursement of all reasonable business expenses incurred or paid by Mr. Polson in the course of performing his duties thereunder. Our General Partner may charge to the Partnership

Mr. Polson's salary and any other amount being paid to Mr. Polson which have not been reimbursed by LBP.

Other: We also reimburse TAC for transportation services, based on a cost-based formula. For the year ended December 31, 2004, we reimbursed TAC $0.1 million. An insignificant amount was incurred for the years ended December 31, 2003 and 2002.

LB Pacific, LP and TAC: LBP and TAC reimbursed us in 2005 for certain costs relating to the LB Acquisition. These included $1.1 million for the Consent Solicitation and $0.4 million for legal and other expenses.

Lehman Brothers, Inc.

Christopher R. Manning, Joshua L. Collins and Jeffrey C. Weber, directors of our General Partner, are each affiliates of Lehman Brothers, Inc. Lehman Brothers, Inc. and its affiliates have, from time to time, performed, and may in the future perform, various financial advisory and investment banking services for us, for which they received or will receive customary fees and expenses. We may engage Lehman Brothers, Inc. and its affiliates from time to time, to perform advisory services for us in connection with acquisitions and financings.

ITEM 14. Principal Accountant Fees and Services

The following table presents fees for professional audit services rendered by our independent registered public accounting firm, KPMG LLP, for the audit of our annual financial statements for the years ended December 31, 2004 and 2003 and fees billed for other services rendered by KPMG LLP during those periods.

For the Year Ended December 31,	2004	2003
	(in thousands)	
Audit fees	$ 848	$ 425
Audit related fees	74	
Tax fees		
All other fees		
Total	$ 922	$ 425

The Audit Committee reviewed and approved, in advance, all services provided by KPMG LLP.

Part IV

ITEM 15. Exhibits and Financial Statement Schedules

(a)(1) and (2) Financial Statements and Financial Statement Schedules

Please see "Index to Consolidated Financial Statements" on page F-1.

(a)(3) Exhibits

The following documents are filed as exhibits to this annual filing:

Exhibit Number	Description
3.1	First Amended and Restated Agreement of Limited Partnership of Pacific Energy Partners, L.P., dated July 26, 2002 (Incorporated by reference to Pacific Energy Partners, L.P.'s Form 10-Q filed on September 5, 2002, Exhibit 3.2)
3.2	Second Amended and Restated Limited Liability Company Agreement of Pacific Energy Group LLC, dated July 26, 2002 (Incorporated by reference to Pacific Energy Partners, L.P.'s Form 10-Q filed on September 5, 2002, Exhibit 3.7)
3.3	Amendment No. 1 to First Amended and Restated Agreement of Limited Partnership of Pacific Energy Partners, L.P., dated August 1, 2003 (Incorporated by reference to Pacific Energy Partners, L.P.'s Form S-3 filed on August 1, 2003, Exhibit 3.3)
3.4	Amendment No. 2 to First Amended and Restated Agreement of Limited Partnership of Pacific Energy Partners, L.P., dated January 27, 2004 (Incorporated by reference to Pacific Energy Partners, L.P.'s Form 10-K filed on March 15, 2004)
3.5	Amendment No. 3 to First Amended and Restated Agreement of Limited Partnership of Pacific Energy Partners, L.P., dated March 26, 2004 (Incorporated by reference to Pacific Energy Partners, L.P.'s Form 10-Q filed on May 5, 2004)
4.1	Form of Indenture of Pacific Energy Partners, L.P. (Incorporated by reference to Pacific Energy Partners, L.P.'s Form S-3 filed on August 1, 2003, Exhibit 4.1)
4.2	Form of Indenture of Pacific Energy Group LLC (Incorporated by reference to Pacific Energy Partners, L.P.'s Form S-3 filed on August 1, 2003, Exhibit 4.2)
4.3	Indenture dated June 16, 2004, by and among Pacific Energy Partners, L.P. and Pacific Energy Finance Corporation, the guarantors named therein, and Wells Fargo Bank, National Association, as trustee of the $7^1/_8$% Senior Notes due 2014 (Incorporated by reference to Pacific Energy Partners, L.P.'s Form 10-Q filed on August 9, 2004, Exhibit 4.2)
4.4	First Supplemental Indenture dated March 3, 2005 by and among Pacific Energy Partners, L.P. and Pacific Energy Finance Corporation, the guarantors named therein, and Wells Fargo Bank, National Association, as trustee of the $7^1/_8$% Senior Notes due 2014 (Incorporated by reference to Pacific Energy Partners, L.P.'s Form 8-K filed on March 9, 2005, Exhibit 4.1)
10.1	U.S. Credit Agreement (Incorporated by reference to Pacific Energy Partners, L.P.'s Form 10-Q filed on September 5, 2002, Exhibit 10.1)
10.2	Amendment No. 1 to U.S. Credit Agreement, dated July 18, 2003 (Incorporated by reference to Pacific Energy Partners, L.P.'s Form 10-K filed on March 15, 2004, Exhibit 10.2)
10.3	Amendment No. 2 to U.S. Credit Agreement, dated December 12, 2003 (Incorporated by reference to Pacific Energy Partners, L.P.'s Form 10-K filed on March 15, 2004, Exhibit 10.3)

Exhibit Number	Description

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10.4	Amendment No. 4 to U.S. Credit Agreement dated May 28, 2004 (Incorporated by reference to Pacific Energy Partners, L.P.'s Form 10-Q filed on August 9, 2004, Exhibit 10.2)
10.5	Canadian Credit Agreement dated May 11, 2004, between Rangeland Pipeline Company (formerly RPC Acquisition Company) and Royal Bank of Canada and other lenders (Incorporated by reference to Exhibit 10.2 to Form 8-K filed May 26, 2004)
10.6	Contribution and Conveyance Agreement (Incorporated by reference to Pacific Energy Partners, L.P.'s Form 10-Q filed on September 5, 2002, Exhibit 10.3)
10.7^	Employment Agreement between Pacific Energy GP, Inc. and Irvin Toole, Jr. (Incorporated by reference to Pacific Energy Partners, L.P.'s Form S-1 filed on July 19, 2002, Exhibit 10.4)
10.8^	Employment Agreement between Pacific Energy GP, Inc. and David E. Wright (Incorporated by reference to Pacific Energy Partners, L.P.'s Amendment No. 3 to Form S-1 filed on July 2, 2002, Exhibit 10.5)
10.9^	Employment Agreement between Pacific Energy GP, Inc. and Gary L. Zollinger (Incorporated by reference to Pacific Energy Partners, L.P.'s Amendment No. 3 to Form S-1 filed on July 2, 2002, Exhibit 10.6)
10.10	Omnibus Agreement (Incorporated by reference to Pacific Energy Partners, L.P.'s Form 10-Q filed on September 5, 2002, Exhibit 10.10)
10.11	First Amendment to Omnibus Agreement (Incorporated by reference to Exhibit 10.1 to Form 8-K filed on March 9, 2005)
10.12^	Form of Pacific Energy GP, Inc. Long-Term Incentive Plan (Incorporated by reference to Pacific Energy Partners, L.P.'s Amendment No. 4 to Form S-1 filed on July 19, 2002, Exhibit 10.8(b))
10.13^	Employment Agreement between Pacific Energy GP, Inc. and Douglas L. Polson (Incorporated by reference to Pacific Energy Partners, L.P.'s Form 10-K filed on March 27, 2003, Exhibit 10.12)
10.14*	Special Agreement between Pacific Energy Management LLC and Douglas L. Polson dated March 3, 2005
10.15*	Consulting Agreement between Pacific Energy Management LLC and Douglas Polson dated March 3, 2005
10.16^	Employment Agreement between Pacific Energy GP, Inc. and Gerald A. Tywoniuk (Incorporated by reference to Pacific Energy Partners, L.P.'s Form 10-K filed on March 27, 2003, Exhibit 10.13)
10.17^	Employment Agreement between Pacific Energy GP, Inc. and Lynn T. Wood (Incorporated by reference to Pacific Energy Partners, L.P.'s Form 10-K filed on March 27, 2003, Exhibit 10.14)
10.18^	Form of Pacific Energy GP, Inc. Annual Incentive Plan (Incorporated by reference to Pacific Energy Partners, L.P.'s Amendment No. 4 to Form S-1 filed on July 19, 2002, Exhibit 10.8(b))
10.19*	First Amending Agreement to the Canadian Credit Agreement dated March 1, 2005, between Rangeland Pipeline Company (formerly RPC Acquisition Company) and Royal Bank of Canada and other lenders
10.20*	Amendment No. 5 to U.S. Credit Agreement, dated December 17, 2004

10.21	Ancillary Agreement (Incorporated by reference to Exhibit 10.1 to Form 8-K filed November 3, 2004)
12.1*	Statement of Computation of Ratio of Earnings to Fixed Charges
21.1*	List of Subsidiaries of Pacific Energy Partners, L.P.
23.1*	Consent of Independent Registered Public Accounting Firm
31.1*	Certification of Principal Executive Officer of Pacific Energy Management LLC, the general partner of Pacific Energy GP, LP, General Partner of Pacific Energy Partners, L.P., as required by Rule 13a-14(a) of the Securities Exchange Act of 1934
31.2*	Certification of Principal Financial Officer of Pacific Energy Management LLC, the general partner of Pacific Energy GP, LP, General Partner of Pacific Energy Partners, L.P., as required by Rule 13a-14(a) of the Securities Exchange Act of 1934
32.1	Certification of Chief Executive Officer of Pacific Energy Management LLC, the general partner of Pacific Energy GP, LP, General Partner of Pacific Energy Partners, L.P., pursuant to 18 U.S.C. §1350
32.2	Certification of Chief Financial Officer of Pacific Energy Management LLC, the general partner of Pacific Energy GP, LP, General Partner of Pacific Energy Partners, L.P., pursuant to 18 U.S.C. §1350

*
Filed herewith.

Not considered to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934 or otherwise subject to the liabilities of that section.

^
Management contract or compensatory plan, contract or arrangement.

SIGNATURES

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

PACIFIC ENERGY PARTNERS, L.P.
By: PACIFIC ENERGY GP, LP, its General Partner
By: By: PACIFIC ENERGY MANAGEMENT LLC, its General Partner

By: /s/ IRVIN TOOLE, JR.

Irvin Toole, Jr.
President, Chief Executive Officer and Director
(Principal Executive Officer)
March 10, 2005

By: /s/ GERALD A. TYWONIUK

Gerald A. Tywoniuk
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial and Accounting Officer)
March 10, 2005

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Partnership in the capacities and on the dates indicated.

Date	Signature	Title
March 10, 2005	/s/ JOSHUA L. COLLINS Joshua L. Collins	Director
March 10, 2005	/s/ DAVID L. LEMMON David L. Lemmon	Director
March 10, 2005	/s/ JOHN C. LINEHAN John C. Linehan	Director
March 10, 2005	/s/ CHRISTOPHER R. MANNING Christopher R. Manning	Director
March 10, 2005	/s/ DOUGLAS L. POLSON Douglas L. Polson	Director

March 10, 2005	/s/ JIM E. SHAMAS Jim E. Shamas	Director
March 10, 2005	/s/ WILLIAM L. THACKER William L. Thacker	Director
March 10, 2005	/s/ JEFFREY C. WEBER Jeffrey C. Weber	Director
March 10, 2005	/s/ FORREST E. WYLIE Forrest E. Wylie	Director

INDEX TO FINANCIAL STATEMENTS

PACIFIC ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors of Pacific Energy Management LLC and Unitholders of
Pacific Energy Partners, L.P.:

We have audited the accompanying consolidated balance sheets of Pacific Energy Partners, L.P. and subsidiaries, as of December 31, 2004 and 2003, and the related consolidated statements of income, partners' capital, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2004. These consolidated financial statements are the responsibility of Pacific Energy Partners, L.P.'s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Pacific Energy Partners, L.P. and subsidiaries as of December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Pacific Energy Partners, L.P. and subsidiaries' internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 10, 2005 expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

/s/ KPMG LLP

Los Angeles, California
March 10, 2005

PACIFIC ENERGY PARTNERS, L.P. AND SUBSIDIARIES (Note 1)
Successor to Pacific Energy (Predecessor)

CONSOLIDATED BALANCE SHEETS

December 31, 2004 and 2003

	2004	2003
	(in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 23,383	$ 9,699
Crude oil sales receivable	28,609	33,766
Transportation and storage accounts receivable	20,137	16,828
Canadian value added tax receivable	7,632	
Crude oil inventory (note 1)	9,174	2,272
Prepaid expenses	4,159	4,182
Other	2,451	2,049
Total current assets	95,545	68,796
Property and equipment, net (note 3)	718,624	567,954
Investment in Frontier (note 5)	7,886	6,886
Other assets, net (note 4)	47,850	6,567
	$ 869,905	$ 650,203
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 15,127	$ 8,816
Accrued crude oil purchases	27,231	31,602
Accrued interest	1,124	2,690
Due to related parties (note 11)	533	580
Derivatives liability current portion (note 9)	400	4,986
Other	3,630	1,317
Total current liabilities	48,045	49,991
Senior notes and credit facilities, net (note 7)	357,163	298,000
Deferred income taxes (note 10)	34,556	
Derivatives liability (note 9)		622
Other liabilities (note 17)	7,675	6,523
Total liabilities	447,439	355,136
Commitments and contingencies (note 17)		
Partners' capital (note 6):		
Common unitholders (19,158,747 and 14,441,763 units outstanding at December 31, 2004 and December 31, 2003, respectively)	361,427	246,952
Subordinated unitholders (10,465,000 units outstanding at December 31, 2004 and 2003)	41,521	49,010
General Partner interest	6,280	3,975
Undistributed employee long-term incentive compensation (note 1)	116	738
Accumulated other comprehensive income (loss) (note 1)	13,122	(5,608)
Net partners' capital	422,466	295,067

	2004	2003
	$ 869,905	$ 650,203

See accompanying notes to consolidated financial statements.

PACIFIC ENERGY PARTNERS, L. P. (Note 1)
Successor to Pacific Energy (Predecessor)

CONSOLIDATED STATEMENTS OF INCOME

Years ended December 31, 2004, 2003 and 2002

	2004	2003	2002
	(in thousands, except per unit amounts)		
Pipeline transportation revenue	$ 108,395	$ 101,811	$ 103,090
Storage and distribution revenue	37,577	12,711	
Pipeline buy/sell transportation revenue	18,640		
Crude oil sales, net of purchases of $402,283, $358,454 and $316,283 in 2004, 2003 and 2002, respectively	16,787	21,293	21,104
Net revenue before expenses	181,399	135,815	124,194
Expenses:			
Operating	84,729	60,649	55,184
Transition costs (note 1)	557	397	2,633
General and administrative	15,400	13,705	7,515
Depreciation and amortization	24,173	18,865	15,919
	124,859	93,616	81,251
Share of net income (loss) of Frontier:			
Income before rate case and litigation expense	1,328	1,459	1,904
Rate case and litigation expense		(1,621)	(557)
Share of net income (loss) of Frontier	1,328	(162)	1,347
Write-down of idle property (note 1)	(800)		
Operating income	57,068	42,037	44,290
Other income	1,032	479	918
Write-off of deferred financing cost and interest rate swap termination expense (note 8)	(2,901)		
Interest expense	(19,209)	(17,487)	(11,634)
Income before income taxes	35,990	25,029	33,574
Income tax (expense) benefit (note 10):			
Current	(326)		
Deferred	65		
	(261)		
Net income	$ 35,729	$ 25,029	$ 33,574
Net income allocated to the general partner interest for 2004 and 2003 and for the period from July 26 through December 31, 2002	$ 715	$ 501	$ 236
Net income allocated to the limited partner interest for the years ended December 31, 2004 and 2003 and for the period from July 26 through December 31, 2002	$ 35,014	$ 24,528	$ 11,581
Basic net income per limited partner unit for the years ended December 31, 2004 and 2003 and for the period from July 26 through December 31, 2002	$ 1.23	$ 1.10	$ 0.55

	2004	2003	2002
Diluted net income per limited partner unit for the years ended December 31, 2004 and 2003 and for the period from July 26 through December 31, 2002	$ 1.23	$ 1.09	$ 0.55
Weighted average limited partner units outstanding for the years ended December 31, 2004 and 2003 and for the period from July 26 through December 31, 2002:			
Basic	28,406	22,328	20,930
Diluted	28,488	22,540	20,930

See accompanying notes to consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. AND SUBSIDIARIES (Note 1)
Successor to Pacific Energy (Predecessor)

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL

Years ended December 31, 2004, 2003 and 2002 (in thousands)

		Limited Partner Units		Limited Partner Amounts					
	Net Parent Investment	Common	Subordinated	Common	Subordinated	General Partner Interest	Undistributed Employee Long-Term Incentive Compensation	Accumulated Other Comprehensive Income (Loss)	Total
Balance, December 31, 2001	$ 157,361			$	$	$	$	$	$ 157,361
Net income for the period of January 1 July 25, 2002	21,757								21,757
Capital contributions of members	8,770								8,770
Distributions to members	(16,000)								(16,000)
Balance, July 25, 2002	$ 171,888			$	$	$	$	$	$ 171,888
Net income for the period July 26 December 31, 2002				5,790	5,791	236			11,817
Distribution to general partner in connection with the initial public offering	(105,081)								(105,081)
Contribution to limited partnership	(66,807)	1,865	10,465	9,767	54,803	2,237			
Proceeds from offering of limited partner interests, net		8,600		151,139					151,139
Distribution to limited partners (post initial public offering)				(3,524)	(3,525)				(7,049)
Distribution to general partner (post initial public offering)						(144)			(144)
Undistributed employee long-term incentive compensation							72		72
Change in fair value of interest rate hedging derivatives (note 1)								(7,375)	(7,375)
Balance, December 31, 2002	$	10,465	10,465	$ 163,172	$ 57,069	$ 2,329	$ 72	$ (7,375)	$ 215,267
Net income				12,963	11,565	501			25,029
Distributions to partners				(21,650)	(19,624)	(841)			(42,115)
Issuance of common units, net of fees and offering expenses		5,612		131,716					131,716
Redemption of common units held by general partner		(1,727)		(40,780)					(40,780)
General partner contribution related to issuance of common units						1,955			1,955
Undistributed employee compensation under long-term incentive plan							3,233		3,233
Issuance of common units pursuant to long-term incentive plan		92		1,531		31	(2,567)		(1,005)

						Undistributed Employee Long-Term Incentive Compensation		
Change in fair value of interest rate and crude oil hedging derivatives							1,767	1,767
Balance, December 31, 2003	$ 14,442	10,465	$ 246,952	$ 49,010	$ 3,975	738	$ (5,608)	$ 295,067
Net income			22,096	12,918	715			35,729
Distributions to partners			(34,981)	(20,407)	(1,130)			(56,518)
Issuance of common units, net of fees and offering expenses	4,625		125,881					125,881
General partner contribution related to issuance of common units					2,690	$		2,690
Undistributed employee compensation under long-term incentive plan						2,076		2,076
Issuance of common units pursuant to long-term incentive plan	92		1,479		30	(2,698)		(1,189)
Foreign currency translation adjustment							13,308	13,308
Change in fair value of interest rate and crude oil hedging derivatives							5,422	5,422
Balance, December 31, 2004	$ 19,159	10,465	$ 361,427	$ 41,521	$ 6,280	$ 116	$ 13,122	$ 422,466

See accompanying notes to consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. AND SUBSIDIARIES (Note 1)
Successor to Pacific Energy (Predecessor)

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years ended December 31, 2004, 2003 and 2002

	2004	2003	2002
		(in thousands)	
Net income	$ 35,729	$ 25,029	$ 33,574
Change in fair value of interest rate hedging derivatives	5,436	1,939	(7,375)
Change in fair value of crude oil hedging derivatives	(14)	(172)	
Change in foreign currency translation adjustment	13,308		
Comprehensive income	$ 54,459	$ 26,796	$ 26,199

See accompanying notes to consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. AND SUBSIDIARIES (Note 1)
Successor to Pacific Energy (Predecessor)

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years ended December 31, 2004, 2003 and 2002

	2004	2003	2002
		(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 35,729	$ 25,029	$ 33,574
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	24,173	18,865	15,919
Amortization of debt issue costs	1,537	1,028	471
Write-off of deferred financing cost	2,321		
Write-down of idle property	800		
Non-cash portion of employee compensation under long-term incentive plan	857	2,199	72
Deferred tax (benefit) expense	(65)		
Share of net (income) loss of Frontier	(1,328)	162	(1,347)
Distribution from (to) Frontier, net	(44)	1,755	1,245
	63,980	49,038	49,934
Net changes in operating assets and liabilities:			
Crude oil sales receivable	5,157	(9,609)	(2,619)
Transportation and storage accounts receivable	(1,311)	(6,260)	(4,798)
Canadian sales tax receivable	(6,725)		
Other current assets	(2,612)	557	(2,582)
Accounts payable and other accrued liabilities	654	1,760	5,316
Accrued crude oil purchases	(4,370)	7,217	2,336
Other non-current assets and liabilities	2,453	51	(294)
Provision for loss on rate case litigation			(1,500)
	(6,754)	(6,284)	(4,141)
NET CASH PROVIDED BY OPERATING ACTIVITIES	57,226	42,754	45,793
CASH FLOWS FROM INVESTING ACTIVITIES:			
Acquisitions	(138,701)	(169,740)	(95,669)
Additions to property and equipment	(16,520)	(10,892)	(5,642)
Other	(731)	300	
NET CASH USED IN INVESTING ACTIVITIES	(155,952)	(180,332)	(101,311)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Issuance of common units, net of fees and offering expenses	125,881	131,716	151,139
Capital contributions from the general partner	2,720	1,955	
Redemption of common units held by the general partner, net of underwriter's fees		(40,780)	
Net proceeds from senior notes offering	240,932		
Repayment of term loan	(225,000)		
Proceeds from note payable to bank	140,922	166,000	312,000
Repayment of long-term debt	(115,253)	(93,000)	(268,333)
Payment of debt issue costs	(1,227)		(5,300)
Distributions to partners (post initial public offering)	(56,518)	(42,115)	(7,193)
Capital contributions of members (pre-initial public offering)			8,770
Distributions to members (pre-initial public offering)			(16,000)
Distributions to general partner in connection with the initial public offering			(105,081)
Due from related party	(47)	(372)	(122)

	2004	2003	2002
NET CASH PROVIDED BY FINANCING ACTIVITIES	112,410	123,404	69,880
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	13,684	(14,174)	14,362
CASH AND CASH EQUIVALENTS, beginning of reporting period	9,699	23,873	9,511
CASH AND CASH EQUIVALENTS, end of reporting period	$ 23,383	$ 9,699	$ 23,873
Supplemental disclosure:			
Cash paid for interest	$ 19,881	$ 16,252	$ 8,551
Non-cash financing and investing activities:			
Additions to equipment	$	$ 204	$

See accompanying notes to consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. AND SUBSIDIARIES
Successor to Pacific Energy (Predecessor)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

On July 26, 2002, Pacific Energy Partners, L.P. and subsidiaries (the "Partnership") completed an initial public offering of common units representing limited partner interests. The Partnership, which was formed by The Anschutz Corporation ("TAC") in February 2002, and its subsidiaries are engaged principally in the business of gathering, transporting, storing and distributing crude oil and other related products in California and the Rocky Mountain region of the U.S. and Canada. The Partnership generates revenue primarily by transporting crude oil on its pipelines and by leasing storage capacity. The Partnership also buys, blends and sells crude oil, activities that are complementary to the Partnership's pipeline transportation business. The Partnership operates primarily in California, Colorado, Montana, Wyoming and Utah in the United States, and in Alberta, Canada and conducts its business through two regional operating units: West Coast Business Unit and Rocky Mountain Business Unit.

The Partnership owns 100% of Pacific Energy Group LLC ("PEG"), whose 100% owned subsidiaries consist of: (i) Pacific Pipeline System LLC ("PPS"), owner of Line 2000 and the Line 63 system, (ii) Pacific Terminals LLC ("PT"), owner of the Pacific Terminals storage and distribution system, (iii) Pacific Marketing and Transportation LLC ("PMT"), owner of the PMT gathering and blending system, (iv) Rocky Mountain Pipeline System LLC ("RMPS"), owner of various undivided interests in the pipelines that make up the Western Corridor system, and 100% of the Salt Lake City Core system, and (v) Ranch Pipeline LLC ("RPL"), owner of a 22.22% partnership interest in Frontier Pipeline Company ("Frontier").

The Partnership also owns 100% of PEG Canada GP LLC ("PEG Canada GP"), the general partner of PEG Canada, L.P. ("PEG Canada"), the operating company for the Partnership's Canadian subsidiaries. The Partnership owns 100% of the limited partner interests in PEG Canada, whose 100% subsidiaries consist of (i) Rangeland Pipeline Company ("RPC"), which owns 100% of Aurora Pipeline Company Ltd. ("APC") and a partnership interest in Rangeland Pipeline Partnership ("RPP"), (ii) Rangeland Northern Pipeline Company ("RNPC"), which owns the remaining partnership interest in RPP, and (iii) Rangeland Marketing Company ("RMC"). RPP owns all of the assets that make up the Rangeland system except the Aurora pipeline, which is owned by APC.

The Partnership also owns 100% of Pacific Energy Finance Corporation. Pacific Energy Finance Corporation was organized for the sole purpose of co-issuing the Partnership's 7.125% senior unsecured notes in June 2004.

In connection with the initial public offering, TAC, through Pacific Energy GP, Inc., an indirect, wholly owned subsidiary of TAC and the general partner of the Partnership (the "General Partner"), conveyed to the Partnership its ownership interests in PEG, whose subsidiaries, at that time, consisted of PPS, PMT, RMPS, RPL and Anschutz Ranch East Pipeline LLC ("AREPI"). TAC made this conveyance in exchange for: (i) the continuation of its 2% general partner interest in the Partnership; (ii) incentive distribution rights (as defined in its partnership agreement); (iii) 1,865,000 common units; (iv) 10,465,000 subordinated units; and (v) the payment of $105.1 million from borrowings under PEG's term loan on closing of the initial public offering.

For the period January 1, 2002 through July 26, 2002, PPS, PMT, AREPI, RMPS and RPL collectively constitute the Partnership's predecessor, and is referred to herein as "Pacific Energy (Predecessor)" or the "Predecessor." The transfer of ownership interest in the entities that constitute

Pacific Energy (Predecessor) to the Partnership represented a reorganization of entities under common control and was recorded at historical cost. The 2002 consolidated financial statements (combined prior to July 26, 2002) include the financial position, results of operations, changes in partners' capital and cash flows of the Partnership, PEG, PPS, PMT, RMPS, AREPI and RPL. AREPI was subsequently merged into RMPS on January 1, 2004 and its AREPI pipeline became part of the Salt Lake City Core system.

All significant intercompany balances and transactions have been eliminated during the consolidation process.

Description of Business and History

PPS was formed in 1998. PPS owns and operates two crude oil pipelines, Line 2000 and the Line 63 system. Line 2000 is a 130-mile crude oil pipeline that extends from Kern County in the San Joaquin Valley of California to the Los Angeles Basin where it has direct and indirect connections to various refineries and terminal facilities. Line 2000 has a permitted annual average throughput capacity of 130,000 barrels of crude oil per day. The Line 63 system includes a 107-mile crude oil pipeline capable of shipping approximately 105,000 barrels of crude oil per day from the San Joaquin Valley to various refineries and delivery points in the Los Angeles Basin and in Bakersfield. The Line 63 system also includes storage assets, various gathering lines in the San Joaquin Valley, distribution lines in the San Joaquin Valley that service refineries in the Bakersfield area, crude oil distribution lines in the Los Angeles Basin and a delivery facility in the Los Angeles Basin.

PMT was formed in June 2001, in connection with the purchase of certain assets in the San Joaquin Valley for approximately $14.4 million. The PMT system consists of 103 miles of intrastate crude oil gathering pipelines as well as truck off-loading and blending facilities at six locations along the gathering system. PMT has a total of approximately 0.3 million barrels of storage capacity, and blending capacity of up to 65,000 barrels per day.

RMPS was formed in December 2001 in connection with the acquisition on March 1, 2002 of the Western Corridor and Salt Lake City Core systems for approximately $107 million. The Western Corridor and Salt Lake City Core system, consist of various ownership interests in 1,967 miles of intrastate and interstate crude oil transportation pipelines, 209 miles of gathering pipelines and 32 storage tanks with approximately 1.5 million barrels of storage capacity. In 2004, the Partnership expanded its pipelines serving Salt Lake City by establishing a new delivery connection from Frontier pipeline to the Salt Lake City Core system.

RPL was formed in 1982. RPL owns a 22.2% partnership interest in Frontier, a Wyoming general partnership, which owns the Frontier pipeline. The Frontier pipeline is a 290-mile pipeline with a throughput capacity of 62,200 barrels per day that originates in Casper, Wyoming and delivers crude oil to the Salt Lake City Core System.

PT was formed in February 2002 in connection with the acquisition on July 31, 2003 of the storage and pipeline distribution system assets of Edison Pipeline and Terminal Company, a division of Southern California Edison (see Note 2 Acquisitions). The storage and distribution system assets acquired by PT consist of 70 miles of distribution pipelines in active service and 34 storage tanks with a total of approximately 9.0 million barrels of storage capacity. Of this total capacity, approximately 6.7 million barrels are in active commercial service, 0.5 million barrels are used primarily for throughput to other storage tanks and do not generate revenue independently, approximately 1.5 million barrels are idle but could be reconditioned and brought into service, and approximately 0.3 million barrels are in displacement oil service.

PEG Canada was formed in 2003 and at December 31, 2004 owned 100% of RPC, APC, RPP, RNPC and RMC. On May 11, 2004, PEG Canada completed the acquisition of all of the outstanding capital stock of RPC, RMC and APC, which owned various components of the Rangeland system and the Aurora pipeline, and a marketing business, for an aggregate cash purchase cost of approximately $118.1 million (see Note 2 Acquisitions).

On June 30, 2004, a subsidiary of PEG Canada completed the acquisition of the Mid-Alberta Pipeline ("MAPL") pipeline for an aggregate cash purchase price of approximately $27.0 million (see Note 2 Acquisitions). MAPL became part of the Rangeland system immediately after closing.

Management Estimates

Preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires that management make certain estimates and assumptions. These estimates and assumptions affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the balance sheet date as well as the reported amounts of revenue and expenses during the reporting period. The actual results could differ significantly from those estimates.

The Partnership's most significant estimates involve the valuation of individual assets acquired in purchase transactions, the useful lives of property and equipment, the expected costs of environmental remediation, accounting for the potential impact of regulatory proceedings or other actions with shippers on the Partnership's pipelines, and the valuation of inventory.

Cash Equivalents

For purposes of the consolidated statements of cash flows, the Partnership considers all highly liquid short-term investments with original maturities of three months or less to be cash equivalents.

Accounts Receivable

Crude oil sales receivable relate to our gathering and blending activities that can generally be described as high volume and low margin activities, in many cases involving complex exchanges of crude oil volumes. Transportation and storage accounts receivable are with shippers who transport crude on our pipelines and lease storage capacity. The Partnership makes a determination of the amount, if any, of the line of credit to be extended to any given customer and the form and amount of financial performance assurances required. Such financial assurances are commonly provided in the form of standby letters of credit. The Partnership also monitor changes in the creditworthiness of its customers as a result of developments related to each customer, the industry as a whole and the general economy.

The Partnership routinely reviews its receivable balances to identify past due amounts and analyze the reasons such amounts have not been collected. In many instances, such delays involve billing delays and discrepancies or disputes as to the appropriate price, volumes or quality of crude oil delivered or exchanged. The Partnership has no allowances for doubtful accounts as of December 31, 2004, 2003 and 2002.

Crude Oil Inventory

Crude oil inventory is valued at the lower of cost or market with cost determined using an average cost method. The crude oil inventory balance is subject to downward adjustment if crude prices decline below the carrying value of the inventory.

Property and Equipment

The components of property and equipment are capitalized at cost and depreciated using the straight-line method over the estimated useful lives of the assets as follows:

Pipelines	40 years
Tanks	40 years
Station and pumping equipment	10-20 years
Buildings	20-30 years
Other	3-15 years

In accordance with our capitalization policy, costs associated with acquisitions and improvements, including related interest costs, which expand our existing capacity are capitalized. For the years ended December 31, 2004 and 2003, capitalized interest was $0.4 million and $0.1 million, respectively. No interest was capitalized during the year ended December 31, 2002. In addition, costs required either to maintain the existing operating capacity of partially or fully depreciated assets or to extend their useful lives are capitalized. Repair and maintenance expenditures associated with existing assets that do not extend the useful life or expand the operating capacity are charged to expense as incurred.

Environmental Remediation and Asset Retirement Obligations

The Partnership accrues environmental remediation costs for work at identified sites where an assessment has indicated that cleanup costs are probable in the future and may be reasonably estimated. These accruals are undiscounted and are based on information currently available, existing technology, the estimated timing of remedial actions and related inflation assumptions and enacted laws and regulations.

A substantial portion of the Partnership's assets have obligations to perform removal and remediation activities when the asset is retired. However, the fair value of the asset retirement obligations cannot be reasonably estimated, as the retirement dates are indeterminate. The Partnership will record such asset retirement obligations in the period in which the retirement dates are determined.

Investments

The investment in Frontier is accounted for using the equity method of accounting. Under the equity method, the investment is initially recorded at cost and subsequently adjusted to recognize the investor's share of distributions and net income or losses of the investee as they occur. Recognition of any such losses is generally limited to the extent of the investor's investment in, advances to, and commitments and guarantees for the investee.

Impairment of Long-Lived Assets

Long-lived assets are reviewed for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. This review consists of a comparison of the carrying value of the asset with the asset's expected future undiscounted cash flows without interest costs. Estimates of expected future cash flows represent management's best estimate based on reasonable and supportable assumptions and projections. If the expected future cash flows exceed the carrying value of the asset, no impairment is recognized. If the carrying value of the asset exceeds the expected future cash flows, impairment exists and is measured by the excess of the carrying value over the estimated fair value of the asset. Any impairment provisions are permanent and may not be restored in the future. For the year ended December 31, 2004, the Partnership recorded an impairment expense of $0.8 million associated with an idle Pacific Terminals property.

Regulation

The California Public Utilities Commission ("CPUC") regulates PPS's common carrier crude oil pipeline operations. All shipments on the regulated pipelines are governed by tariffs authorized and approved by the CPUC. Tariffs on the Line 2000 pipeline are market-based, established based on market considerations subject to certain contractual terms. Tariffs on the Line 63 pipeline are cost-of-service based, designed to allow PPS to recover its various costs to operate and maintain the pipeline as well as a charge for depreciation of the capital investment in the pipeline and an authorized rate of return.

The CPUC also regulates PT's storage and distribution operations. The CPUC has authorized PT to establish the terms, conditions and charges for its storage and distribution services through negotiated contracts with its customers.

The PMT gathering and blending system is a proprietary intrastate operation that is not regulated by the CPUC or the Federal Energy Regulatory Commission ("FERC").

The Western Corridor and the Salt Lake City Core systems are common carrier pipelines that transport oil under cost-based tariffs under the jurisdiction of the FERC and the Wyoming Public Service Commission ("WPSC").

The Rangeland system operates as a proprietary system, and accordingly the Partnership takes title to the crude oil that is gathered and transported. The Rangeland system is subject to the jurisdiction of the Alberta Energy Utilities Board ("EUB"). Aurora pipeline is subject to the Canadian National Energy Board ("NEB"). The EUB and NEB will generally not review rates set by a crude oil pipeline operator unless it receives a complaint.

Revenue Recognition

Revenue from pipeline transportation services is recognized upon delivery of the crude oil to the customer. Other revenue associated with the operation of the Partnership's pipelines is recognized as the services are performed.

Storage and distribution revenue is recognized monthly based on the lease of storage tanks, the use of distribution system assets, and the delivery of related incidental services.

The Rangeland system is a proprietary system therefore, customers who wish to transport commodities on the Rangeland system must either: (i) sell commodities at the inlet to the pipeline without repurchasing commodities; or (ii) sell commodities at an inlet point and repurchase such product at agreed-upon delivery points for the price paid at the inlet to the pipeline plus an established location differential on a pre-arranged basis. Buy/sell transactions are recognized on a net basis.

PMT's crude oil sales are recognized as the crude oil is delivered to customers, and are reflected separately, net of crude oil purchases, on the accompanying consolidated statements of income.

Transition Costs

Transition costs include costs incurred in connection with the transition of the operations of acquired assets from the seller to the Partnership.

Derivative Instruments

The Partnership uses, on a limited basis, certain derivative instruments to hedge its exposure to commodity price risk and and its exposure to interest rate risk. The Partnership records all derivative instruments on the balance sheet as either assets or liabilities measured at their fair value under the provisions of SFAS 133, "Accounting for Derivative Instruments and Hedging Activities" as amended.

SFAS 133 requires that changes in the fair value of derivative instruments be recognized currently in earnings unless specific hedge accounting criteria are met, in which case changes in fair value are deferred to accumulated other comprehensive income and reclassified into earnings when the underlying transaction affects earnings. Accordingly, changes in fair value are included in the current period for (i) derivatives characterized as fair value hedges, (ii) derivatives that do not qualify for hedge accounting and (iii) the portion of cash flow hedges that is not highly effective in offsetting changes in cash flows of hedged items (See Note 9 for further discussion of derivatives).

Concentration of Customers and Credit Risk

A substantial portion of the West Coast transportation and storage business in 2004, 2003 and 2002 was with four customers who accounted for approximately 73%, 76% and 71% of West Coast transportation and storage revenue, respectively. Two of these customers, ChevronTexaco and Shell Trading Company, who accounted for approximately 46%, 47% and 51% of 2004, 2003 and 2002 transportation and storage revenue have executed ten-year ship or pay agreements, expiring in 2009, with the Partnership, whereby they have committed to ship minimum volumes that represent approximately 52% of their actual 2004 volumes transported on the Partnership's pipelines. These agreements mitigate certain of the potential adverse consequences of the concentration of customers of the Partnership.

A substantial portion of the Partnership's Rocky Mountain pipeline transportation business in 2004, 2003 and 2002 was with customers who, in total, accounted for approximately 40%, 50% and 68% of total Rocky Mountain transportation revenue in those years. In 2004 and 2003, two customers comprised these percentages and in 2002 the percentage was comprised of four customers. In addition, for the Partnership's Canadian buy/sell transportation revenue, two customers accounted for approximately 60% of our net sales revenue and one vendor accounted for 66% of our net purchase contracts.

Although the above concentration could affect the Partnership's overall exposure to credit risk, management believes that the Partnership is exposed to minimal risk since a majority of its business is conducted with major, high credit quality companies within the industry. The Partnership performs periodic credit evaluations of its customers' financial condition and generally does not require collateral for its accounts receivables. In some cases, the Partnership requires payment in advance or security in the form of a letter of credit or bank guarantee.

Foreign Currency Translation

The financial statements of operating subsidiaries in Canada are prepared using the Canadian dollar as the functional currency. Balance sheet amounts are translated at the end of period exchange rate. Income statement and cash flow amounts are translated at the average exchange rate for the period. Adjustments from translating these financial statements into U.S. dollars are recognized in the equity section of the balance sheet under the caption, "accumulated other comprehensive income (loss)."

Income Taxes

The Partnership and its U.S. and Canadian subsidiaries are not taxable entities in the U.S. and are not subject to U.S. federal or state income taxes as the tax effect of operations is passed through to its unitholders. The Partnership's Canadian subsidiaries are taxable entities in Canada and are subject to Canadian federal and provincial income taxes and other Canadian income taxes. In addition, monies repatriated from Canada into the U.S. may be subject to withholding taxes.

Net income for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under the Partnership's First Amended and Restated Agreement of Limited Partnership, as amended. Individual unitholders have different investment bases depending upon the timing and price of acquisition of partnership units. Further, each unitholder's tax accounting, which is partially dependent upon the unitholder's tax position, differs from the accounting followed in the consolidated financial statements. Accordingly, the aggregate difference in the basis of the Partnership's net assets for financial and tax reporting purposes cannot be readily determined because information regarding each unitholder's tax attributes in the Partnership is not available to the Partnership.

In addition to federal and state income taxes, unitholders may be subject to other taxes, such as local, estate, inheritance or intangible taxes which may be imposed by the various jurisdictions in which the Partnership does business or owns property. Individual unitholders will generally have no responsibility to file Canadian tax returns.

Income taxes are accounted for under the asset and liability method. Under this method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in operations in the period that includes the enactment date. The Partnership intends to repatriate its Canadian subsidiaries' earnings in the future. As such, the Partnership records a provision for Canadian withholding taxes on any unremitted earnings of its Canadian subsidiaries.

Business Segment Reporting

The business segments of the Partnership consist of two geographic regions, the West Coast and the Rocky Mountains. The West Coast Business Unit includes PPS, PMT and PT. The Rocky Mountain Business Unit includes RMPS, RPL and PEG Canada and its Canadian subsidiaries RPC, APC, RPP, RNPC and the RMC. Information relating to these two segments is summarized in Note 15 Segment Information.

Net Income per Unit

Basic net income per limited partner unit is determined by dividing net income, after deducting the amount allocated to the general partner interest, by the weighted average number of outstanding limited partner units.

Diluted net income per limited partner unit is calculated in the same manner as basic net income per limited partner unit above, except that the weighted average number of outstanding limited partner units is increased to include the dilutive effect of outstanding options and restricted units by application of the treasury stock method. Set forth below is a reconciliation of the basic weighted average outstanding limited partner units to diluted weighted average outstanding limited partner units.

	Year Ended December 31,		
	2004	2003	2002
		(in thousands)	
Basic weighted average limited partner units	28,406	22,328	20,930
Effect of restricted units	67	202	
Effect of unit options	15	10	
Diluted weighted average limited partner units	28,488	22,540	20,930

Restricted Units and Unit Options

As permitted under Statement of Financial Accounting Standards No. 123 ("SFAS No. 123"), "Accounting for Stock-Based Compensation," the Partnership has elected to measure costs for restricted units and unit options using the intrinsic value method, as prescribed by Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees." Compensation expense related to the restricted units is recognized by the Partnership over the vesting periods of the units. Accordingly, the compensation expense related to the restricted units that is allocable to the current reporting period has been recognized in the accompanying consolidated statements of income, and non-cash employee compensation related to the long-term incentive plan is included in "undistributed employee long-term incentive compensation" in the accompanying consolidated balance sheets. No compensation expense related to the unit options has been recognized in the accompanying consolidated financial statements. Had the Partnership determined compensation cost based on the fair value at the grant date for its unit options under SFAS No. 123, "Accounting for Stock-Based Compensation," net income would have been reduced less than $0.1 million in 2004, 2003 and 2002 and the effect on earnings per limited partner unit would have been less than $0.01 per limited partner unit in 2004, 2003 and 2002.

Reclassifications

Certain prior year balances in the accompanying consolidated financial statements have been reclassified to conform to the current year presentation.

Recent Accounting Pronouncements

In December 2004, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 123 (revised December 2004), *Share-Based Payment (SFAS 123R)*. This Statement is a revision of SFAS No. 123. SFAS 123R establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services. SFAS 123R is effective for the Partnership as of the beginning of the first interim period or annual reporting period that begins after June 15, 2005. The adoption of SFAS 123 is not expected to have a material impact on the Partnership's consolidated financial statements.

2. ACQUISITIONS

Canadian Assets

Rangeland

On May 11, 2004, the Partnership completed the acquisition of all of the outstanding shares of Rangeland Pipeline Company ("RPC"), Rangeland Marketing Company ("RMC") and Aurora Pipeline Company Ltd. ("APC"), the corporations that owned various components of the Rangeland system and the related marketing business from BP Canada Energy Company ("BP"). The Rangeland system is located in the province of Alberta, Canada. The purchase price for the shares of RPC, RMC and APC was Cdn$130.1 million plus approximately Cdn$32.2 million for assumed liabilities, linefill, working capital and transaction costs. The aggregate purchase price was approximately U.S. $118.1 million and was funded through a combination of proceeds from the Partnership's March 30, 2004 equity offering and a Cdn$45 million borrowing from a new Cdn$100 million revolving credit facility in Canada. The acquisition was accounted for as an acquisition of assets.

The majority of the Rangeland system was constructed in 1966, with smaller portions being built as early as 1955, and certain pump stations built as late as 1971. The Partnership is depreciating the pipeline over forty years from the purchase date.

Pursuant to a transportation service agreement between RMC and RPC, RMC has contracted for the rights to the entire capacity of the Rangeland system's pipelines. Customers who wish to transport product on the Rangeland system must, therefore, either: (i) sell product to RMC at the inlet to the pipeline without repurchasing product from RMC; or (ii) sell product to RMC at an inlet point and repurchase such product at agreed upon delivery points for the price paid at the inlet to the pipeline plus an established location differential. RMC owns the buy/sell contracts with customers, which were assumed with the purchase.

The Rangeland system was historically operated by BP without regard to maximizing either pipeline throughput or profitability; rather, it was operated as an integral part of a larger marketing and trading oriented enterprise. Similarly the MAPL pipeline, which the Partnership also purchased (see "Mid Alberta Pipeline" below), was not operated with regard to maximizing pipeline operations or profitability; it was operated as a cost center in a larger enterprise. The Partnership is making significant changes to the revenue-generating capability of both systems by combining and integrating fully all of its Canadian and U.S. Rocky Mountain pipeline systems under common management, by expanding the throughput capacity of the MAPL pipeline, and by connecting into other pipelines and establishing a new pump station and receiving terminal in Edmonton, Alberta. This new facility will be able to access additional sources of Canadian crude oil, which will allow the Partnership to participate in transporting the projected increase in production of Canadian synthetic crude oil. Construction of the new facility is expected to be complete in the fourth quarter of 2005.

In effect, the Partnership is converting what has been primarily a gathering system for crude oil, condensate and butane in southern Alberta into a trunk line transportation system that will be able to transport multiple grades of conventional and synthetic crude oils from the Edmonton oil hub to U.S. Rocky Mountain refining centers.

Until April 2003, the assets comprising the Rangeland system were held by three legal entities: BP, APC and BP Canada Energy Resources Company ("BPR"). In April 2003, in order to facilitate their sale, BPR formed RPC and RMC, and transferred the Rangeland pipeline and marketing assets to the newly formed entities. APC, which contains only a short segment of pipeline and *de minimis* other assets, liabilities, revenues and expenses, remained unchanged. None of RPC, RMC or APC ever had any employees of their own. All operations and administrative and technical support functions associated with the Rangeland system, including field services and operations, executive management, marketing, engineering, environmental, risk management, payroll, treasury, human resources and legal remained with BPR and BP. These included services provided by approximately 90 BP employees who also provided varying amounts of support for BP's other pipelines.

Although the RPC and RMC legal entities were formed in April 2003, revenues, expenses, and other financial measures continued to be included within the financial statements of BPR and BP. Financial statements for RPC, RMC and Aurora were not maintained on a current basis.

Upon closing of the purchase transaction, BP terminated employees directly involved in the operation of the Rangeland system, including field-level supervisors, and the Partnership hired those who accepted an offer of employment. Except for one former marketing person (who had not been directly involved with marketing of the Rangeland system for several years), no members of senior management, and no financial, marketing or technical personnel who had been associated with the management and support of the Rangeland system, or marketing for RMC, were made available by BP for possible employment with the Partnership following the completion of this acquisition. Consequently, the Partnership hired its own marketing, accounting and technical staffs, which are located in its new Calgary, Alberta office or in Olds, Alberta. The Partnership also utilizes its existing executive and support staff in Long Beach, California and Denver, Colorado to provide management oversight and administrative and technical support for the Alberta assets.

The existing accounting software and computer hardware were not included with the assets purchased by the Partnership. The Partnership was able, however, to acquire as part of the transaction, the Supervisory Control and Data Acquisition (SCADA) system necessary to operate the pipeline. Subsequent to the closing, the Partnership acquired software associated with the complex task of volumetric and revenue accounting from the seller for no additional consideration. The Partnership uses its existing financial accounting software for other accounting functions.

Mid Alberta Pipeline

On June 30, 2004, the Partnership completed the acquisition of the MAPL pipeline from Imperial Oil. The MAPL pipeline is located in Alberta, Canada. The purchase price for MAPL was Cdn$31.5 million, of which Cdn$5.0 million is payable June 30, 2007. In addition to the MAPL pipeline, the Partnership acquired linefill for Cdn$5.0 million. The aggregate purchase price, including assumed liabilities, linefill, and transaction costs was approximately U.S.$27.0 million, most of which was funded from the Partnership's existing Canadian credit facility.

The first section of MAPL pipeline was constructed in 1960 and other sections were constructed in 1985 and 1994. The Partnership is depreciating the pipeline over 40 years from the date of purchase.

Imperial Oil did not make any of its employees available for possible employment with the Partnership following the completion of the acquisition. In connection with the purchase, the Partnership entered into a two-year transitional services agreement with Imperial Oil whereby Imperial Oil provides necessary services to operate the initiating pump station and the control center and software that control movements through the MAPL pipeline. The Partnership has the right to cancel the transitional services agreement at any time. The Partnership expects to assume all MAPL pipeline operations and transfer MAPL operations to the Partnership's Rangeland control center after its initiation facilities in Edmonton are constructed and operational.

The existing accounting software or computer hardware was not included with the assets purchased by the Partnership. The task of volumetric and revenue accounting has been consolidated with the accounting process for the Rangeland system. The Partnership uses its existing financial accounting software for other accounting functions.

Following the acquisition, the MAPL pipeline assets were integrated into and are operated as part of the Rangeland system.

Purchase Price Allocation

The consolidated statements of income include the results of Rangeland and MAPL from their acquisition dates. Based upon independent appraisals of the fair values of the acquired assets, the following is a summary of the consideration paid and purchase price allocation (U.S.$ in thousands):

Consideration:	
Purchase price	$ 114,595
Payments for working capital, linefill, minimum tank inventories and other items	22,486
Transaction costs	1,620
Assumed liabilities	6,486
Subtotal	145,187
Deferred tax liability assumed	30,348
Total consideration	$ 175,535
Purchase price allocation:	
Pipelines, equipment and property	$ 120,838
Pipeline linefill and minimum tank inventories	17,620
Intangible assets	32,392
Working capital	4,685
Total	$ 175,535

Pacific Terminals Storage and Distribution System

On July 31, 2003, PT completed the acquisition of the storage and pipeline distribution system assets of Edison Pipeline and Terminal Company, a division of Southern California Edison Company, for a purchase price of $158.2 million plus $9.7 million of adjustments for displacement oil, minimum tank inventory, certain pre-closing capital expenditures, customary working capital adjustments and other costs. In addition, $1.5 million of transaction costs were incurred and $3.6 million of liabilities were assumed by PT in connection with the acquisition. These assets, which comprise the PT storage and distribution system, consist of 70 miles of distribution pipelines in active service and 34 storage tanks with a total of approximately 9.0 million barrels of storage capacity. Of this total capacity approximately 6.7 million barrels are now in active commercial service, 0.5 million barrels are used primarily for throughput to other storage tanks and do not generate revenue independently, approximately 1.5 million barrels are idle but could be reconditioned and brought into service, and approximately 0.3 million barrels are in displacement oil service. The PT storage and distribution system is used by the Partnership to serve the crude oil and other dark products storage and distribution needs of the refining, pipeline, and marine terminal industries in the Los Angeles Basin. The purchase was funded through $90.0 million of proceeds from the issuance of additional common units on August 25, 2003, and borrowings under the Partnership's revolving credit facility.

The acquisition was accounted for as a purchase and, accordingly, the consolidated statements of income include the results of PT beginning August 1, 2003. Based upon independent appraisals of the fair values of the acquired assets, the following is a summary of the consideration paid and purchase price allocation (in thousands):

Consideration:		
Purchase price	$	158,200
Payments for working capital and reimbursement of certain other expenditures		9,746
Transaction costs		1,524
Assumed liabilities		3,550
Total consideration	$	173,020
Purchase price allocation:		
Land	$	63,943
Storage tanks, pipelines and other equipment		103,783
Displacement oil, minimum tank inventories, spare parts and other		4,484
Intangible assets		810
Total	$	173,020

The acquisition of the PT storage and distribution system resulted in negative goodwill of $20.5 million, which was allocated proportionately to reduce property and equipment and displacement oil and minimum tank inventories of PT.

3. PROPERTY AND EQUIPMENT

Property and equipment consists of the following amounts:

	December 31, 2004	December 31, 2003
	(in thousands)	
Pipelines	$ 501,821	$ 391,270
Land and land improvements	73,068	71,214
Tanks	76,719	65,028
Station and pumping equipment	75,641	59,272
Buildings	13,580	13,538
Other	26,511	17,330
Construction in progress	15,998	12,828
	783,338	630,480
Less accumulated depreciation	(92,526)	(69,439)
	690,812	561,041
Displacement oil, pipeline linefill and minimum tank inventory	27,812	6,913
	$ 718,624	$ 567,954

Depreciation expense for each of the three years in the period ended December 31, 2004, was $23.4 million, $18.2 million and $15.3 million, respectively

4. OTHER ASSETS

Other assets included in the accompanying balance sheet consist of the following:

	December 31, 2004	December 31, 2003
	(in thousands)	
Amortizable intangibles	$ 38,733	$ 2,382
Deferred financing costs	8,548	6,313
Fair value of interest rate swaps	2,693	
	49,974	8,695
Less accumulated amortization	(2,124)	(2,128)
	$ 47,850	$ 6,567

SFAS 142 requires that intangible assets with finite useful lives be amortized over their respective estimated useful lives. If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset shall be amortized over the best estimate of its useful life. The Partnership will assess the useful lives of all intangible assets each reporting period to determine if adjustments are required. All of the Partnership's intangibles have finite lives and are amortized on a straight line basis over the expected lives of the intangibles. The weighted average expected life of intangibles at December 31, 2004 was approximately 38.5 years. Amortization expense on amortizable intangible assets was $0.8 million, $0.6 million and $0.4 million for the years ended December 31, 2004, 2003 and 2002, respectively.

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The following table sets forth future estimated amortization expense on amortizable intangible assets, net of accumulated amortization at December 31, 2004 as follows (in thousands):

Years ending December 31,	
2005	$ 1,227
2006	1,219
2007	999
2008	999
2009	975
Thereafter	32,474
	$ 37,893

5. INVESTMENT IN FRONTIER

RPL owns a 22.22% partnership interest in Frontier which is accounted for by the equity method of accounting. Under the equity method, the investment is initially recorded at cost and subsequently adjusted to recognize the investor's share of distributions and net income or loss of the investee as they occur. Recognition of any such loss is generally limited to the extent of the investor's investment in, advances to, and commitments and guarantees for the investee. The summarized balance sheets and income statements are presented below (unaudited):

Balance Sheets

	December 31,	
	2004	2003
	(in thousands)	
ASSETS		
Current assets	$ 2,785	$ 2,013
Property and equipment, net	9,109	8,900
Other assets	1	1
	$ 11,895	$ 10,914
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities	$ 1,257	$ 6,953
Other liabilities	2,020	2,159
Partners' capital	8,618	1,802
	$ 11,895	$ 10,914

Statements of Income

	Year Ended December 31,		
	2004	2003	2002
	(in thousands)		
Revenue	$ 11,268	$ 9,775	$ 11,253
Operating expense	(4,270)	(3,644)	(2,520)
Depreciation expense	(368)	(364)	(359)
Operating income	6,630	5,767	8,374

	Year Ended December 31,		
Rate case and litigation expense		(7,295)	(2,504)
Other income (expense)	(14)	157	194
Net income (loss)	$ 6,616	$ (1,371)	$ 6,064

The unamortized portion of the excess cost over the Partnership's share of net assets of Frontier is $6.7 million and $6.9 million at December 31, 2004 and 2003, respectively. This excess cost over the Partnership's share of net assets represents the difference between the historical cost and the fair value of property and equipment at acquisition dates. The Partnership is amortizing this excess cost over the life of the related property and equipment.

6. PARTNERS' CAPITAL

On August 1, 2003, the Partnership, PEG and certain subsidiaries of PEG filed a universal shelf registration statement on Form S-3 with the SEC to register the issuance and sale, from time to time and in such amounts as is determined by the market conditions and needs of the Partnership, of up to $550.0 million of common units of the Partnership and debt securities of both the Partnership and PEG. The registration statement also registered possible future sales of up to 1,865,000 common units held by the General Partner, which acquired these common units as partial consideration for its contribution to the Partnership of assets and liabilities in connection with the Partnership's initial public offering. The SEC declared the registration statement effective on August 8, 2003.

On August 25, 2003, the Partnership issued and sold 5,000,000 common units in an underwritten public offering at a price of $24.66 per common unit before underwriting fees and offering expenses. In addition, the Partnership granted the underwriters an option to purchase up to an additional 750,000 common units to cover over-allotments, if any. The underwriters exercised a portion of the over-allotment option and purchased an additional 500,000 common units on August 29, 2003 and 112,000 common units on September 3, 2003 at the offering price of $24.66 per common unit. Net proceeds received from the initial offering and partial exercise of the over-allotment option totaled approximately $131.7 million, after deducting underwriting fees and offering expenses of $6.7 million. The Partnership used the net proceeds from the offering and a related capital contribution of the General Partner of $2.0 million to repay $90.0 million of indebtedness outstanding under PEG's revolving credit facility which had been incurred in connection with the acquisition of the PT storage and distribution system assets, and to redeem 1,727,100 common units owned by the General Partner for $40.8 million, or $23.612 per common unit. The remaining net proceeds were retained by the Partnership. Following redemption, the 1,727,100 redeemed common units were cancelled.

On March 30, 2004, the Partnership issued and sold 4,200,000 common units in an underwritten public offering at a price of $28.50. The common units sold in the offering were registered pursuant to the registration statement on SEC Form S-3 filed on August 1, 2003. Net proceeds from the offering, including the Partnership's general partner's contribution of $2.4 million, totaled approximately $116.7 million after deducting underwriting fees and offering expenses of $5.4 million. The Partnership repaid approximately $10 million in borrowings under its U.S. revolving credit facilities, which were incurred in the first quarter of 2004 to fund the deposit on the Rangeland acquisition, and used approximately $76 million of the net proceeds to fund a portion of the aggregate purchase price of the Rangeland and Mid Alberta pipeline acquisitions. The Partnership utilized the remaining $31 million in net proceeds to repay borrowings under its U.S. revolving credit facility.

On April 12, 2004, the underwriters exercised a portion of the over-allotment option granted in connection with the offering of common units on March 30, 2004 and purchased an additional 425,000 common units from the Partnership at a price of $28.50 per unit to cover over allotments. Including the related capital contribution of the General Partner of $0.2 million, the Partnership received net proceeds of $11.8 million after underwriting fees. The Partnership used the $11.8 million in net proceeds from the exercise of the overallotment option to reduce the balance outstanding under its U.S. revolving credit facility.

7. LONG-TERM DEBT

The Partnership's long-term debt obligations are shown below:

	December 31,	
	2004	2003
	(in thousands)	
Senior secured U.S. revolving credit facility	$ 51,000	$ 73,000
Senior secured Canadian revolving credit facility	54,005	
Senior notes, net of unamortized discount of $4,202 and including fair value increase of $2,693	248,491	
Senior secured term loan		225,000
Future payment for MAPL assets, net of unamortized discount of $480	3,667	
Total	357,163	298,000
Less current portion		
Long-term debt	$ 357,163	$ 298,000

Principal payments due on long-term debt during each of the five years subsequent to December 31, 2004 are as follows: (in thousands):

Year ending December 31,	
2005	$
2006	
2007	108,672
2008	
2009	
Thereafter	248,491
Total	$ 357,163

Senior Secured U.S. Revolving Credit Facility and Term Loan

The U.S. revolving credit facility is a $200.0 million facility which matures on July 26, 2007 and is available for general partnership purposes, including working capital, letters of credit and distributions to unitholders, and to finance future acquisitions. Borrowings under the revolving credit facility are limited by various financial covenants in the credit agreement. The revolving credit facility has a borrowing sublimit of $45.0 million for working capital, letters of credit and partnership distributions to unitholders.

The U.S. revolving credit facility bears interest at the Partnership's option, at either (i) the base rate, which is equal to the higher of the prime rate as announced by Fleet National Bank or the Federal Funds rate plus 0.50% or (ii) LIBOR plus an applicable margin ranging from 0.75% to 2.00%. The applicable margins are subject to change based on the credit rating of the revolving credit facility or, if is not rated, the credit rating of the Partnership's U.S. operating subsidiary, Pacific Energy Group LLC. The Partnership incurs a commitment fee which ranges from 0.125% to 0.375% per annum on the unused portion of the revolving credit facility.

As of December 31, 2004, $51.0 million was outstanding under the revolving credit facility and $106 million of undrawn credit was available under the credit facility.

The revolving credit facility is the primary obligation of PEG and is guaranteed by the Partnership, certain of PEG's U.S. operating subsidiaries, and PEG Canada, PEG Canada GP LLC and Pacific

Energy Finance Corporation (collectively, the "Guarantors"). The revolving credit facility is fully recourse to PEG and the guarantors, but non-recourse to the General Partner. Obligations under the revolving credit facility are secured by (i) the assets of the Partnership, (ii) pledges of membership interests in and the assets of PEG and certain of PEG's operating subsidiaries and PEG Canada GP LLC, (iii) pledges of partnership interests in and certain assets of PEG Canada, and (iv) pledges of the shares in and the assets of Pacific Energy Finance Corporation; provided, however, that the collateral under the credit agreement does not include shares, partnership interests, limited liability company membership interests or other ownership interest, if any, in or assets of Rangeland Pipeline Company, Rangeland Marketing Company, Rangeland Northern Pipeline Company, Rangeland Pipeline Partnership, Aurora Pipeline Company Ltd. or any other entity that is designated by PEG or the Partnership after the date hereof as an "Unrestricted Subsidiary" pursuant to the terms of the credit agreement.

Under the U.S. credit agreement, PEG is prohibited from declaring dividends or distributions if any event of default, as defined in the credit agreement, occurs or would result from such declaration. In addition, the credit agreement contains certain financial covenants and covenants limiting the ability of PEG and the Guarantors to, among other things, incur or guarantee indebtedness, change ownership or structure, including mergers, consolidations, liquidations and dissolutions, sell or transfer their assets and properties, declare or pay dividends and enter into a new line of business. At December 31, 2004, PEG and Guarantors were in compliance with all such covenants.

On June 16, 2004, the Partnership repaid all amounts outstanding under the term loan. Amounts under the term loan that have been repaid may not be re-borrowed.

Canadian Revolving Credit Facility

On May 11, 2004, Rangeland Pipeline Company, a Canadian subsidiary of the Partnership, entered into a Cdn$100 million revolving credit facility agreement which is guaranteed by the other Canadian subsidiaries of the Partnership. The Canadian revolving credit facility is secured by liens on all of the property and assets of the Partnership's Canadian subsidiaries.

Indebtedness under the Canadian revolving credit facility bears interest, at Rangeland Pipeline Company's option, at either (i) the Canadian prime rate or the U.S. base rate (each plus an applicable margin ranging from 1.00% to 1.625%), or (ii) Bankers' Acceptance discount rates, or LIBOR plus an applicable margin ranging from 2.00% to 2.65%. The applicable margins are subject to change based on certain financial ratios.

The Canadian revolving credit facility matures on May 11, 2007. Amounts outstanding under the credit facility may be repaid at any time prior to maturity.

The Canadian revolving credit facility is available for general corporate purposes and also provides for the issuance of letters of credit. Borrowings under this facility are limited by various financial covenants that are set forth in the Canadian credit agreement. As of December 31, 2004, Rangeland Pipeline Company was in compliance with all covenants under the Canadian agreement. At December 31, 2004, borrowings totaling Cdn$65.0 million (U.S.$54.0 million) and letters of credit totaling Cdn$5.0 million (U.S.$4.1 million) were outstanding under the Canadian revolving credit facility. As of December 31, 2004, the Partnership had available but undrawn credit of Cdn$21million (U.S.$17 million) under its Canadian revolving credit facility.

Rangeland Pipeline Company incurs a commitment or standby fee which ranges from 25% to 35% of the applicable margin, based on the unused portion of the Canadian revolving credit facility. Under the Canadian credit agreement, Rangeland Pipeline Company is prohibited from declaring dividends or making any other distributions or payments to its parent or its affiliates if any default or event of default, as defined in the Canadian credit agreement, occurs or would result from such declaration or payment, or if a material adverse effect, as defined in the Canadian credit agreement, would result from such declaration or payment, or if the distributions and payments would exceed certain limits. The Canadian credit agreement also contains covenants requiring Rangeland Pipeline Company, including its subsidiaries and affiliates, to maintain specified financial ratios. In addition, the Canadian credit agreement contains other restrictive covenants. As of December 31, 2004, Rangeland Pipeline Company was in compliance with all covenants under the Canadian credit agreement.

7.125% Senior Notes

On June 16, 2004, the Partnership and its 100% owned subsidiary, Pacific Energy Finance Corporation, completed the sale of $250 million of 7.125% senior notes due June 15, 2014 (the "Senior Notes"). The Senior Notes were sold in a private offering to qualified institutional buyers in reliance on Rule 144A under the Securities Act of 1933 (the "Securities Act") and to non-U.S. persons under Regulation S of the Securities Act. In October 2004, the Senior Notes were exchanged for new notes with materially identical terms that have been registered under the Securities Act but are not listed on any securities exchange. The Senior Notes were issued at a discount of $4.4 million, resulting in an effective interest rate of 7.375%. Interest payments are due on June 15 and December 15 of each year, beginning on December 15, 2004. At any time prior to June 15, 2007, the Partnership has the option to redeem up to 35% of the aggregate principal amount of notes at a redemption price of 107.125% of the principal amount with the net cash proceeds of one or more equity offerings. The Partnership has the option to redeem the Senior Notes, in whole or in part, at anytime on or after June 15, 2009 at the following redemption prices:

Year	Percentage
2009	103.563%
2010	102.375%
2011	101.188%
2012 and thereafter	100.000%

The Senior Notes are jointly and severally guaranteed by certain of the Partnership's subsidiaries, including Pacific Energy Group LLC, Pacific Marketing and Transportation LLC, Rocky Mountain Pipeline System LLC, Ranch Pipeline LLC, PEG Canada GP LLC and PEG Canada, L.P.

In addition, the indenture governing the Senior Notes contains certain covenants that, among other things, limit the Partnership's ability and the ability of its restricted subsidiaries to incur or guarantee indebtedness or issue certain types of preferred equity securities; sell assets; pay distributions on, redeem or repurchase Partnership units; consolidate, merge or transfer all or substantially all of its assets. At December 31, 2004, the Partnership was in compliance with all such covenants.

Net proceeds from the issuance of the Senior Notes were $240.9 million after deducting the $4.4 million discount and offering expenses of $4.7 million. The net proceeds were used principally to repay the Partnership's $225 million term loan and to repay $16 million of indebtedness outstanding under the Partnership's U.S. revolvin