PACIFIC ENERGY PARTNERS LP
Form 10-K
March 13, 2006

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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, 2005**

or

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

1-31345
(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 if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ý No o

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

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. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Large accelerated filer Yes o No o Accelerated filer Yes ý No o Non-accelerated filer Yes o No o

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

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, 2005, the last business day of the registrant's most recently completed second fiscal quarter, was approximately $610,000,000, based on a price per common unit of $31.75, the closing price of the common units as reported on the New York Stock Exchange on such date. There were approximately 31,450,000 of the registrant's common units and 7,848,750 of the registrant's subordinated units outstanding as of February 28, 2006.

Documents incorporated by reference: None.

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References in this annual report on Form 10-K to "Pacific Energy Partners," the "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:

Anschutz	The Anschutz Corporation
Aurora	Aurora Pipeline Company Ltd.
bbl	Barrels
bpd	Barrels per day
Colorado PUC	Colorado Public Utilities Commission
CPUC	California Public Utilities Commission
dark products	Crude oil and refinery feedstocks such as gas oil and heavy fuel oils
DOT	U.S. Department of Transportation
EUB	Alberta Energy and Utilities Board
FERC	Federal Energy Regulatory Commission
Frontier	Frontier Pipeline Company
LB Acquisition	The purchase on March 3, 2005 by Lehman Brothers Merchant Banking Group of its interest in Pacific Energy Partners, L.P.
LBMB	Lehman Brothers Merchant Banking Group
LBP	LB Pacific, LP
mbpd	One thousand barrels per day
NEB	Canadian National Energy Board
PAT	Pacific Atlantic Terminals LLC
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 Ranch, 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
Ranch	Ranch Pipeline LLC
Rangeland Partnership	Rangeland Pipeline Partnership
SEC	Securities and Exchange Commission
Valero Acquisiton	The purchase by the Partnership on September 30, 2005 of certain San Francisco area and Philadelphia area terminals, and the West Pipeline system, from Valero, L.P. (See "Items 1&2. Business and Properties Significant Events in 2005")
Wyoming PSC	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, refined products and other dark products and buying and selling crude oil. Please see "Item 1A-Risk Factors" 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, refined products and other related products. We generate revenue primarily by transporting such commodities on our pipelines, by leasing capacity in our storage tanks, and by providing other terminaling services. We also buy and sell crude oil, activities that are generally complementary to our other crude oil operations. We conduct our business through two business units, the West Coast Business Unit, which includes activities in California and the Philadelphia, Pennsylvania area, and the Rocky Mountain Business Unit, which includes activities in five Rocky Mountain states and Alberta, Canada. 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 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 ("Anschutz") (see "Significant

Developments in 2005 Sale of The Anschutz Corporation's Interest in Us"). Pacific Energy GP, LP is managed by its general partner, Pacific Energy Management LLC ("PEM"), a Delaware limited liability company, thus the officers and Board of Directors of PEM manage the business affairs of the Partnership and Pacific Energy GP, LP. Our General Partner is owned by LB Pacific, LP ("LBP"), which is owned by private equity funds managed by Lehman Brothers, Inc. and First Reserve Corporation ("First Reserve"). References 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.

Our General Partner does not receive any management fee or other compensation in connection with its management of our business, but is entitled to reimbursement for all direct and indirect expenses incurred on our behalf. Our principal executive offices are located at 5900 Cherry Avenue, Long Beach California 90805, and our phone number is (562) 728-2800.

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 Atlantic Terminals LLC ("PAT"), owner of the California and East Coast assets we purchased on September 30, 2005 as part of the acquisition of assets from Valero, L.P. (see "Significant Events in 2005 Acquisition of Assets From Valero" below);

(iv) Pacific Marketing and Transportation LLC ("PMT"), owner of the PMT gathering system and marketing business;

(v) Rocky Mountain Pipeline System LLC ("RMPS"), owner of the Western Corridor system, the Salt Lake City Core system and the Rocky Mountain Products Pipeline (formerly the West Pipeline System), which was acquired on September 30, 2005 as part of the acquisition of assets from Valero, L.P.; and

(vi) Ranch Pipeline LLC ("Ranch"), the owner of a 22.22% partnership interest in Frontier Pipeline Company ("Frontier"), a Wyoming general partnership.

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. ("Aurora") and a partnership interest in Rangeland Pipeline Partnership ("Rangeland Partnership"),

(ii) Rangeland Northern Pipeline Company ("RNPC"), which owns the remaining partnership interest in Rangeland Partnership, and

(iii) Rangeland Marketing Company ("RMC").

Rangeland Partnership owns all of the assets that make up the Rangeland pipeline system except the Aurora pipeline, which is owned by Aurora.

We also own 100% of Pacific Energy Finance Corporation, co-issuer of our $7^1/_8$% senior notes due 2014 and $6^1/_4$% senior notes due 2015.

The chart that follows depicts the organization and ownership of the Partnership as of January 31, 2006. The chart does not include Pacific L.A. Marine Terminals LLC, which was established to

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construct and operate Pier 400. See "West Coast Business Unit Pier 400" below for further discussion of our Pier 400 project.

Significant Events in 2005

Acquisition of Assets from Valero, L.P.

On September 30, 2005, we completed the purchase of certain terminal and pipeline assets (the "Valero Acquisition") from Support Terminals Operating Partnership, L.P., Kaneb Pipe Line Operating Partnership, L.P. and Shore Terminals LLC (the "Sellers") for an aggregate purchase price of approximately $455 million, plus $11.5 million for the assumption of certain environmental and operating liabilities and $3.7 million for closing costs. The assets purchased consist of (i) the Martinez terminal and Richmond terminal in the San Francisco, California area, (ii) the North Philadelphia and South Philadelphia terminals and the Paulsboro, New Jersey terminal in the Philadelphia, Pennsylvania area, and (iii) a 550-mile refined products pipeline system, formerly known as the West Pipeline System, with four terminals in the U.S. Rocky Mountains (collectively, the "Valero Assets").

The Martinez and Richmond terminals currently have 4.1 million barrels of combined storage capacity. The terminals handle refined products, blend stocks and crude oil, and are connected to a network of owned and third-party pipelines that carry crude oil and light products to and from area refineries. These terminals also receive and deliver crude oil and light products by marine vessel or barge. The Richmond terminal has a rail spur for delivery and receipt of light products and a truck rack for product delivery.

The North Philadelphia, the South Philadelphia and the Paulsboro, New Jersey terminals handle refined products and have a combined storage capacity of 3.1 million barrels. The terminals receive product via connections to third-party pipelines and have truck racks for deliveries. The North Philadelphia and Paulsboro terminals can also deliver and receive products by marine vessel or barge.

The 550-mile refined products pipeline system, now called the Rocky Mountain Products Pipeline, extends from Casper, Wyoming east to Rapid City, South Dakota and south to Colorado Springs, Colorado. The pipeline system includes products terminals at Rapid City, South Dakota, Cheyenne, Wyoming and Denver and Colorado Springs, Colorado with a combined storage capacity of 1.7 million barrels. The Rocky Mountain Products Pipeline has various segments with different receipt and delivery points. The various segments of the trunk line have a combined current throughput capacity of approximately 85,000 barrels per day.

We have integrated the operations, maintenance, marketing and business development of the Rocky Mountain Products Pipeline with our existing pipeline activities in the Rocky Mountain Business Unit. We have also similarly integrated the San Francisco area terminals and Philadelphia area terminals with our existing pipeline and terminal activities in our West Coast Business Unit.

Sale of The Anschutz Corporation's Interest in Us

On March 3, 2005, Anschutz completed the sale of its interest in the Partnership to LBP an entity formed by Lehman Brothers Merchant Banking Group. 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 the Partnership and the incentive distribution rights, and (ii) 10,465,000 subordinated units of the Partnership which represented, at the time, a 34.6% limited partner interest. 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 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 PEM, its general partner. 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. 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 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 governance guidelines and its compensation structure and employee benefit plans and policies.

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 of significant independent storage facilities and a large distribution system in the Los Angeles Basin and San Francisco Bay area, as well as being the owner of the only two common carrier pipelines serving the Los Angeles Basin, 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. The storage facilities effectively operate as an extension of the refineries' operations. Our crude oil pipelines 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 to Bakersfield, California. We continually seek opportunities to maximize the utilization of our storage facilities, to increase the capacity of our storage facilities and to capture additional volumes for our pipelines. We believe the strategic position of our West Coast assets creates other development opportunities that will help us maintain and increase cash flows, including the development opportunity presented by the Pier 400 project (see "West Coast Business Unit" below).

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. The 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 Canadian crude oil, including synthetic crude oil, replace declining crude oil production in the U.S. Rocky Mountain region. With the acquisition in 2004 of the Rangeland and MAPL pipelines in Alberta, we now have an integrated pipeline corridor from Edmonton, Alberta, a primary oil hub, to the major refining centers in the U.S. Rocky Mountain region.

The terminal facilities acquired from Valero, L.P. are also located in highly desirable locales for refined product demand. Both the Martinez and Richmond storage facilities are located in the growing San Francisco Bay area and are well positioned to participate in the increasing imports of refined products, feedstocks and ethanol, and in the case of the Martinez facility, crude oil. The East Coast terminals are located in the densely populated Philadelphia, Pennsylvania area and are connected to the Colonial and Sun pipelines, two of the major transporters of refined products to the Northeastern region of the United States. The Paulsboro, New Jersey facility is located on the Delaware River with excellent deepwater access to accommodate vessels up to 100,000 deadweight tons.

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

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 on a per unit basis;
- strengthen and enhance our existing business units; and
- expand outside our existing business units into the 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 and believe our acquisition history, reputation and project development 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 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 development phase of our Pier 400 Project;
- in May 2004, we acquired the Rangeland system for approximately $118 million;
- in June 2004, we acquired the MAPL pipeline for approximately $27 million; and
- in September 2005, we completed the Valero Acquisition for approximately $470 million.

Minimize our exposure to commodity price volatility. We have historically managed our business to minimize our direct exposure to volatile commodity prices. We believe this strategy of minimizing our exposure to commodity price volatility will continue to enhance our ability to generate stable cash flow.

We do not take title to the crude oil or refined products we transport on our pipelines and store in our storage facilities, except with respect to our crude oil buying and selling activities in California, and to a lesser extent in other areas, which in the aggregate has been a small percentage of net revenue (9% in 2005), and for operational imbalances at our refined products terminals 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 on it. However, most 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.

West Coast Business Unit

Our West Coast Business Unit is comprised of the following assets which are 100% owned:

- Line 2000
- Line 63 system
- Pacific Terminals storage and distribution business
- PMT gathering system and marketing business
- Pacific Atlantic Terminals (San Francisco area terminals and Philadelphia area terminals)

Our West Coast Business Unit 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 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 Outer Continental Shelf producing fields, Point Arguello and the Santa Ynez Unit, to the Los Angeles Basin and Bakersfield. We also own and operate the PMT gathering 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 servicing the Los Angeles Basin. We have integrated the recently acquired San Francisco area terminals and Philadelphia area terminals with our existing pipeline and terminal activities in our West Coast Business Unit (see "Significant Events in 2005 Acquisition of Assets from Valero L.P." for a description of these assets) and are currently seeking permits for the development of a deepwater petroleum import terminal at Pier 400 and Terminal Island in the Port of Los Angeles. Our West Coast Business Unit is headquartered in Long Beach, California, with field offices in Bakersfield and in the San Francisco, California, and Philadelphia, Pennsylvania areas.

Market Overview

General Market Considerations. The market in Southern California for our crude oil 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 dark products on our pipelines and in our storage facilities.

Our Martinez and Richmond, California terminals are the predominant independent terminals in the San Francisco Bay area and are well positioned to capitalize on increasing imports of crude oil and refined petroleum products into the state of California. The combined storage capacity of the Philadelphia, Pennsylvania and Paulsboro, New Jersey terminals also position us as one of the largest independent terminal operators in the region, able to serve the needs of various refiners, marketers, major petroleum jobbers and end-users. The terminals offer a variety of services that appeal to a broad range of customers.

Sources of Demand. Refined products such as gasoline, diesel fuel, jet fuel and heating oils 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 that ranks the state third highest in the nation. In addition to serving 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. The California refineries were designed to process San Joaquin Valley heavy crude oil and Outer Continental Shelf crude oil, which are both transported by our pipelines but can also be transported north to the San Francisco Bay area refineries. 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. To the extent San Joaquin Valley and Outer Continental Shelf crude oil is transported to the San Francisco refineries, the refineries we serve will be required to obtain their crude oil from other sources such as Alaskan North Slope and foreign crude oil. Because 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, 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. San Joaquin Valley 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 San Joaquin Valley crude oil is transported to the San Francisco Bay area rather than to the Los Angeles Basin.

Our San Francisco area terminals are the largest independently owned terminals in the area and serve northern and central California and Nevada markets with refined products. The terminals are connected to all five San Francisco Bay area refineries through pipeline connections with third-party pipelines. The terminals' customers also receive a significant portion of their refined products from marine vessels.

Similarly, our Philadelphia, Pennsylvania, and Paulsboro, New Jersey, terminals serve densely populated areas, which affect the demand for refined products. Our Philadelphia area terminals provide services and products to all six of the refiners in the Philadelphia harbor. Using our facilities, these refineries receive feedstock from New York Harbor, the United States Gulf Coast, and foreign imports. Our diverse facilities and infrastructure allow us to provide storage and throughput services to brokers, marketers and refiners who are our customers.

Sources of Supply. California is the fourth largest oil producing area in the United States, including production from the Federal Outer Continental Shelf. In addition to the local California-produced crude oil, major ports in San Francisco and Los Angeles/Long Beach receive waterborne Alaskan North Slope 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 Alaskan North Slope production may impact us in the future if shippers elect to replace Alaskan North Slope crude oil delivered to San Francisco area refineries with San Joaquin Valley and Outer Continental Shelf crude.

We expect that the natural production declines from the California fields we serve will result in growth of water-borne imports to the Los Angeles Basin and the San Francisco Bay area. We expect to participate in this growth through our Pacific Terminals storage and distribution system, our San Francisco Bay area terminals and, if successful, our proposed development of the Pier 400 Project.

Our San Francisco area terminals are supplied from local refineries and by marine vessels. Our Philadelphia area refined products terminals depend on connections with refineries and petroleum products pipelines owned and operated by third parties as a significant source of supply and also receive waterborne products from the U.S. Gulf Coast and the New York Harbor.

Line 2000

We own and operate Line 2000, an intrastate common carrier crude oil pipeline that transports crude oil produced in the San Joaquin Valley and California Outer Continental Shelf to the Los Angeles Basin. Line 2000 is a 130-mile, insulated trunk pipeline originating at our Emidio Pump Station in Kern County, California and delivers crude oil directly and indirectly to refineries and terminal facilities in the Los Angeles Basin. Because Line 2000 is insulated, 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 2005, approximately 67,900 bpd was transported on Line 2000. Line 2000 is capable of transporting multiple batches and grades of heavy crude oil.

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 transportation contracts with certain of our shippers, which allow us to raise our tariff rates in response to increases in various inflation-based indices and market factors. The CPUC reviews our tariff rates when changes are sought. On May 1, 2005, we increased the tariff rates on Line 2000 by approximately 4.8%, based on the contractually agreed index of cost changes.

The Line 63 System

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 Outer Continental Shelf 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 crude oil on the Line 63 system. Line 63 has a throughput capacity of approximately 105,000 bpd. In 2005, approximately 51,700 bpd was transported on Line 63.

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. Additionally, effective August 1, 2005, we implemented a temporary surcharge of $0.10 per barrel on our long-haul tariff rates to recover our uninsured costs relating to the oil release, pipeline repairs and other costs incurred as a result of record rains in Southern California (see "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations Significant Developments in 2005").

Pacific Terminals Storage and Distribution System

The Pacific Terminals storage and distribution system complements our West Coast 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. In the fourth quarter of 2005, we received permission from the CPUC to dismantle certain idle PT assets and sell the underlying land, which has an estimated value of approximately $10 million at December 31, 2005. In addition, in the fourth quarter of 2005, we sold one parcel of idle PT land for net proceeds of $1.6 million.

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 2006, 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 dock use agreement on terms that are materially similar to current terms but there are no assurances that we will be successful in this regard. Currently, we pass through to our customers 100% of the costs to utilize this dock.

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.

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.

Pacific Marketing and Transportation Gathering System and Marketing Business

In addition to our primary pipeline operations, we are engaged in buying, gathering and selling crude oil, activities that are generally complementary to our pipeline transportation business in California's San Joaquin Valley and in the Rocky Mountain area in the vicinity of our pipelines. Beginning in the third quarter of 2005, we also selectively purchase and resell crude oil in other areas as well, although this is not a focus area for us.

The PMT gathering network is located in the San Joaquin Valley and consists of 103 miles of gathering pipelines as well as truck off-loading and gathering 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 gathering capacity. The PMT gathering network in California effectively extends our pipeline network to capture supplies of crude oil for transportation on our trunk pipelines to Los Angeles that might not otherwise be shipped through our pipelines. We contract for third-party trucks to collect crude oil from remote areas that are not connected to our gathering system. We generate net revenue from our gathering activity by capturing the difference in price between the crude oil gathered at various locations and the higher price of the crude oil delivered.

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 that, the pricing of our sales barrels can vary from the cost of our gathered barrels. We conduct crude oil hedging to protect our inventory positions from major changes in market prices. 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.

Our PMT gathering system is a proprietary intrastate operation that is not regulated by the CPUC.

Pacific Atlantic Terminals (San Francisco area terminals and Philadelphia area terminals)

Our San Francisco area terminals, which include the Martinez and Richmond terminals, currently have 48 storage tanks with 4.1 million barrels of combined storage capacity that are connected to area refineries through a network of owned and third-party pipelines that carry crude oil and refined products to and from area refineries. The terminals have dock facilities that can load between approximately 4,000 and 10,000 barrels per hour of refined products. There is also a rail spur at the Richmond terminal that is able to load and receive products by train. The Martinez terminal is permitted for an additional 1.3 million barrels of storage capacity and we have begun constructing three new 150,000 barrel storage tanks, which we are expecting to place in service in July 2006.

The San Francisco area terminals generate revenue primarily by leasing storage tank capacity to major traders and refiners in the San Francisco area. Most leases are under "ever-green" contracts for a year or longer and are privately negotiated with customers. Most of the San Francisco area terminals' revenue is from these storage leases.

Our Philadelphia area terminals, which include the North Philadelphia, South Philadelphia and the Paulsboro, New Jersey terminals, have 40 storage tanks with combined storage capacity of 3.1 million barrels. The terminals have 20 truck loading lanes, two barge docks and a ship dock. The Philadelphia area terminals provide services and products to all of the refiners in the Philadelphia harbor. The North Philadelphia and Paulsboro terminals have dock facilities that can load approximately 10,000 to 12,000 barrels per hour of refined products. The Philadelphia area terminals also receive products from the Colonial and Sun pipelines. The terminals also offer truck loading services and barge cleaning and tug fuel services. The terminals generate approximately 50% of their revenue by leasing storage capacity and approximately 50% of their revenue by delivering products from the terminal facilities to our customers' trucks and marine vessels.

The San Francisco and Philadelphia area terminals are not regulated as utilities.

Pier 400

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, and we recently completed an updated cost estimate. We are estimating that Pier 400 will cost approximately $250 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 3.0 million barrels of storage, although we are seeking permits for, and will likely build, 4.0 million barrels of storage. We are 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, the Los Angeles City Council and the U.S. Army Corps of Engineers. We expect to have the necessary permits in the second half of 2006.

We have entered into agreements with ConocoPhillips and two subsidiaries of Valero Energy Corporation that provide long term customer commitments to off-load a total of 140,000 bpd of crude oil at the Pier 400 dock. The Valero and ConocoPhillips agreements are subject to satisfaction of various conditions, such as, the achievement of various progress milestones, financing, continued economic viability, and completion of other ancillary agreements related to the project. We are negotiating similar long term off-loading agreements with other potential customers.

We expect the Pier 400 Project to be completed and placed in service in late 2007 or early 2008. We anticipate funding of the remaining pre-construction costs to be incurred through the end of 2006 from our existing revolving credit facility. Construction of the terminal facility is expected to be financed on a long-term basis through a combination of debt and proceeds from the issuance of additional partnership units, including common units.

Customers

Each of the following customers represent greater than 10% of transportation and storage revenue for our West Coast operations for 2005: BP America Production Company; Chevron; Shell Trading Company; and Valero Marketing and Supply Company. We have ship or pay agreements, expiring in 2009, with two customers, Chevron and Shell Trading Company, whereby they have committed to ship minimum volumes on Line 2000 that represent approximately 61% of their actual 2005 volumes transported on Line 2000.

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.

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.

The competition in our gathering and marketing business and our terminaling and storage operations include other crude oil and refined products companies, the major integrated oil companies and their marketing affiliates, and independent gatherers, and brokers and marketers of widely varying sizes, financial resources and experience. Some of these competitors have capital resources many times greater than ours, and control greater supplies of crude oil and refined products. Some of our competitors, such as major integrated oil companies, have storage facilities that they use for their own purposes. In addition, some of our competitors may be our customers that purchase crude oil directly at the producing field.

Rocky Mountain Business Unit

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

- Rangeland system
- Western Corridor System (made up of varying ownership interests)
- Salt Lake City Core System
- Frontier Pipeline (22.22% partnership interest)

In addition, we own the Rocky Mountain Products Pipeline.

Our 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. We deliver to the refineries either directly through our pipelines or indirectly through connections with third-party pipelines. Deliveries are also made to the refining and marketing center of Edmonton, Alberta from the Rangeland system.

In addition, our Rocky Mountain Business Unit includes the Rocky Mountain Products Pipeline (See "Significant Events in 2005 Acquisition of Assets from Valero L.P."), which supplies the South Dakota, Wyoming and Colorado refined products markets.

Our Rocky Mountain Business Unit is headquartered in Denver, Colorado with a marketing and operations office in Calgary, Alberta. We have nine field offices in the U.S. Rocky Mountains and three in Alberta.

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 process 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 for crude oil. 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 other markets in Utah, as well as to Wyoming, Idaho, Oregon, Washington and Nevada.

Refined products are supplied on the Rocky Mountain Products Pipeline to the South Dakota, Wyoming and Colorado markets, including the Denver metropolitan area.

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 could benefit our Rocky Mountain operations in two ways: first, more Canadian synthetic crude should be available for transport on our pipelines for use by the U.S. Rocky Mountain refining centers, and second, more

Canadian conventional crude oil could be transported on our 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. Rocky Mountain markets.

The Rocky Mountain Products Pipeline receives refined products from Wyoming, Montana and Denver area refineries through its pipelines or connections with third-party pipelines.

Rangeland System

The Rangeland system includes the Rangeland pipeline and what was formerly referred to as 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. In 2005, 21,000 bpd of crude oil was transported on the segment of the pipeline from Sundre north to Edmonton and 47,100 bpd was transported on the pipeline from Sundre south to the United States.

The Rangeland system historically served several types of conventional crude oil production areas in central and southern Alberta. By acquiring the MAPL pipeline in 2004 and completing the construction of the new station in Edmonton in March 2006, we are linking the Rangeland pipeline to the Edmonton oil hub to access supplies of synthetic crude oil for transportation south to the U.S.

We are currently constructing an 80,000 barrel tank at the Edmonton station and a 120,000 barrel tank in Sundre to better facilitate the movement of synthetic crude oil.

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 our exposure to commodity price volatility.

Substantially all of the pipelines that comprise the Rangeland system are subject to the jurisdiction of the Alberta Energy and 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, 2005, the location differentials were increased by an average of 6.9%.

Western Corridor System

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. 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 first quarter of 2006.

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 2005, approximately 18,200 bpd of Canadian crude oil was transported through our Glacier pipeline throughput capacity. ConocoPhillips Pipe Line Company is the operator of the 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 2005, approximately 12,800 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 the 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 2005, approximately 12,800 bpd of Canadian crude oil and 6,300 bpd of U.S. Rocky Mountain crude oil was transported on our Big Horn throughput capacity. We operate the Big Horn Pipeline.

Under our contracts with ConocoPhillips Pipe Line Company, we manage our undivided interest in the Western Corridor system independently of ConocoPhillips 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 ConocoPhillips 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. We are currently constructing two additional tanks with total storage capacity of 240,000 barrels. These storage assets are used primarily to facilitate the transportation of the crude oil on our portion of the throughput capacity of the pipelines.

The FERC and the Wyoming PSC 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 our ability to file for the maximum permitted rates.

Salt Lake City Core System

We own 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 2005, approximately 101,600 bpd was delivered to Salt Lake City directly through our pipelines and of this amount approximately 59,200 bpd was delivered indirectly through connections to a Chevron 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 connects to a Chevron pipeline that serves Salt Lake City. In 2005, the northern segment delivered approximately 42,400 bpd and the southern segment delivered approximately 13,500 bpd to Salt Lake City. In addition, approximately 45,700 bpd was transported from Frontier/Evanston Station, Utah to Kimball Junction, Utah, approximately 11,900 bpd was transported from Reno to Casper, Wyoming and approximately 3,300 bpd from Reno to Guernsey, Wyoming. In 2004, we completed a $3.4 million, 7,000 bpd expansion into Salt Lake City.

We plan to construct a new 16-inch pipeline, approximately 91 miles in length, which will for much of its distance parallel and use the common rights-of-way of our existing pipeline to Salt Lake City. The new pipeline will be able to transport multiple grades of crude oil in segregated batches, including various types of Canadian heavy and synthetic crude oil. It has been designed to provide the capacity necessary to meet the increasing crude oil demand in Salt Lake City, both in the near-term and well into the future. The new pipeline will be constructed in two phases, with construction of the first phase scheduled to begin in March 2006 and be completed in October 2006. The completion of the first phase will add additional capacity into Salt Lake City of approximately 12,000 bpd. The second phase is expected to be completed in October 2007. Capacity of the completed pipeline will be approximately 95,000 to 140,000 bpd, depending on the mix of heavy and light crude oils. Holly Energy Partners, L.P. and Enbridge Inc. have announced that they are studying a competing pipeline construction project. It is not known what impact it would have on our expansion project if their pipeline is constructed.

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 trucking operations do not represent a significant portion of our total operating income.

The FERC and the Wyoming PSC 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 actual filed rates may be limited by competitive forces. The FERC tariff rates generally increase each July 1 by the amount of change in the Producer Price Index for finished goods.

Frontier Pipeline

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 pipeline. 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 2005, approximately 47,300 bpd was transported on Frontier pipeline.

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

Rocky Mountain Products Pipeline

Our Rocky Mountain Products Pipeline includes approximately 550 miles of pipeline in Wyoming, Colorado and South Dakota, and four truck-loading terminals. The system's four refined products terminals have a total storage capacity of over 1.7 million barrels. The Rocky Mountain Products Pipeline originates near Casper, Wyoming, where it serves as a connecting point with Sinclair's Little America Refinery and the ConocoPhillips Seminole Pipeline, which transports product from Billings, Montana area refineries. The system continues to Douglas, Wyoming where it branches off to serve our Rapid City, South Dakota terminal approximately 190 miles away. This segment also receives product from Wyoming Refining Company via a third-party pipeline at a connection located near the border of Wyoming and South Dakota. From Douglas, Wyoming, the Rocky Mountain Products Pipeline continues south to our terminals at Cheyenne, Wyoming, where it receives refined products from the Frontier Refining Company refinery via a third-party pipeline, and continues on to Denver, Colorado and Colorado Springs, Colorado. Our Denver terminal also receives refined products from Sinclair Pipeline. The various segments of the Rocky Mountain Products Pipeline have a combined throughput capacity of 85,000 bpd. For the period from acquisition on September 30, 2005 through December 31, 2005, 60,200 bpd in total was transported on the various segments of the Rocky Mountain Products Pipeline. The capacities of the Rocky Mountain Products Pipeline terminals are as follows:

- The Rapid City terminal has 14 tanks with approximately 269,000 barrels of storage capacity;
- The Cheyenne terminal has 16 tanks with approximately 343,000 barrels of storage capacity;
- The Denver terminal has 18 tanks with approximately 692,000 barrels of storage capacity; and
- The Colorado Springs terminal has 15 tanks with approximately 394,000 barrels of storage capacity.

The FERC, Wyoming PSC, and the Colorado PUC each regulate various tariffs on the Rocky Mountain Products Pipeline. The FERC tariff rates generally increase each July 1 by the amount of change in the Producer Price Index for finished goods. The Wyoming PSC and Colorado PUC tariffs have also been periodically modified by reference to the FERC tariff indexing levels.

Customers

Each of the following customers represents greater than 10% of net transportation revenue for our Rocky Mountain operations for 2005: Chevron and Tesoro. We have not entered into any transportation contracts with respect to crude oil transported on our 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, which was completed in March 2006 with construction of an initiating pump station and a pipeline connection in Edmonton, and construction of several tanks in Alberta and Montana, all of which will allow for transportation of synthetic crude oil. 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.

Trans Mountain System. The 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 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 2005, the Express/Platte pipeline expanded its total system capacity from 172,000 bpd to 280,000 bpd.

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 our 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.

ConocoPhillips Western Corridor System. ConocoPhillips Pipe Line Company owns an interest in the Glacier, Beartooth and Big Horn pipelines, which comprise our Western Corridor system.

ConocoPhillips 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.

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.

The Rocky Mountain Products Pipeline competes with various pipelines serving the Cheyenne, Denver and Colorado Springs markets. In Denver, product can be received from ConocoPhillips and Valero, L.P. pipelines from the southeast and delivered over their proprietary racks. Denver can also receive product via Sinclair's pipeline from Sinclair, Wyoming. The Magellan Midstream Partners, L.P. pipeline delivers product from the east to an affiliated terminal and to Sinclair's Henderson terminal for deliveries both into the Denver market and for export to Salt Lake City. Similarly, Valero's pipeline and terminal in Colorado Springs provide alternative sources of supply. In addition, shippers are able to enter into various exchange agreements to minimize transportation related costs. The Rocky Mountain Products Pipeline terminals compete directly with other terminals in the Denver and Colorado Springs markets. In addition, some of our competitors may be our customers that use our facilities.

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

We operate all of our U.S. pipelines from five consoles located at our main office in Long Beach, California 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 our 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 first quarter of 2006.

In general, the Supervisory Control and Data Acquisition ("SCADA") systems we use to operate our pipelines 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 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 wall integrity of our pipelines, providing data as to wall thickness, corrosion and other anomalies that might indicate potential 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, 2005, we have internally inspected 100% of our California trunk pipelines and 69% of our distribution lines. During the same period, we smart pigged approximately 63% of the U.S. Rocky Mountain pipelines we operate and approximately 55% of our Rangeland trunk pipeline. All of the refined products pipelines acquired as part of the Valero Acquisition were smart pigged during this period.

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. Our Aurora 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 involve examination of 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 EUB. With respect to the portion of the Rangeland system 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 and refined products pipeline operations (collectively referred to as "petroleum pipelines" in this section) are subject to tariff rate regulation by the FERC under the Interstate Commerce Act. The Interstate Commerce Act requires that tariff rates for petroleum pipelines 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 a 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 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 ("AOPL") 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 24, 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. The next 5-year review is currently underway, with the FERC having proposed to continue use of the unadjusted producer price index. AOPL submitted comments supporting an index based on the Producer Price Index plus 1.3 percent. Various parties filed responsive comments in support of both the FERC's and AOPL proposals. A final decision by FERC, which will be effective as of July 1, 2006, remains pending.

Another development affecting petroleum pipeline ratemaking arose in Opinion No. 397, involving Lakehead Pipe Line Company, L.P., (now known as Enbridge Energy Partners, 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 an 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 thereafter initiated a broader inquiry into the implications of the court's decision on other FERC-regulated companies. That was followed by issuance on May 4, 2005 of the FERC's "Policy Statement on Income Tax Allowances" ("Policy Statement"), which addressed the circumstances in which a partnership or other pass-through entity would be permitted to include a tax allowance in its cost of service. On December 16, 2005, the FERC issued its "Order on Initial Decision and on Certain Remanded Cost Issues" in various dockets involving SFPP (the "SFPP Order"). Among other things, the SFPP Order applied the Policy Statement to the specific facts of the SFPP case, suggesting how the FERC will treat other limited partnership petroleum pipelines. The SFPP Order confirmed that a limited partnership is entitled to a tax allowance with respect to partnership income for which there is an "actual or potential income tax liability" and determined that a unitholder that is required to file a Form 1040 or Form 1120 tax return that includes partnership income or loss is presumed to have an actual or potential income tax liability sufficient to support a tax allowance on that partnership income. The FERC also established certain other presumptions, including that corporate unitholders are presumed to be taxed at the maximum corporate tax rate of 35% while individual unitholders (and certain other types of unitholders taxed like individuals) are presumed to be taxed at a 28% tax rate. The SFPP Order remains subject to further administrative proceedings (including compliance filings by SFPP and possible rehearing requests), as well as potential judicial review. While those further proceedings 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. Various parties to SFPP proceeding have petitioned the D.C. Circuit for review of the order. The court has directed the parties to submit by January 3, 2006 a briefing schedule for judicial review. 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. 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 and Terminals. 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. The Western Corridor and Salt Lake City systems have intrastate movements that are regulated by the Wyoming PSC, and the Rocky Mountain Products Pipeline is regulated by the Wyoming PSC and the Colorado PUC. All Colorado and Wyoming intrastate tariffs are subject to cost-of-service based tariff limitations. 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 Salt Lake City Core system does make intrastate crude oil deliveries, but the state of Utah does not regulate intrastate oil pipelines. The Pacific Terminals system is also regulated by the CPUC, but it has been authorized to negotiate and execute individual contracts with customers for storage, pipeline distribution and other utility services.

Cost-of-service ratemaking methodologies vary by state, but they are generally designed to allow the pipeline to recover (1) the costs to operate and maintain pipeline assets, including general and administrative costs, (2) depreciation of capital assets, (3) a return on the depreciated, historical capital investment and capital additions to the pipeline facilities, and (4) the associated taxes. Although the amounts we are authorized to charge under these tariffs are determined by reference to cost-of-service factors, our actual filed rates are often limited by free-market and competitive factors. For this reason, 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. Generally, to change cost-based 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 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. Rules governing changes to tariff rates vary by state, but typically the pipeline must file a rate application that is subject to agency review, and that may be protested by shippers or other interested parties and subject to an agency hearing.

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. Market-based rates are not expressly authorized in all states, and Line 2000, in California, is the only pipeline we own that is authorized to use such rates for its intrastate tariffs. To qualify for market-based rates in California, the pipeline must 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. Modifications to market-based rates can be protested and set for hearing, but the grounds for protest should be more limited than for cost-of-service based rate filings because 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.

All of our rates and terms of service are subject to review by the agencies having jurisdictional authority in each respective state, either on their own initiative or at the urging of a shipper or interested party, and proceedings may be commenced to change or reduce rates or alter the terms and conditions of service. In addition, state legislatures or regulatory agencies may modify ratemaking methodologies with resulting tariffs that generate lower revenue and cash flow.

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, is regulated by the NEB. Aurora is designated as a Group 2 company. 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 owner 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. Depending on the nature and extent of a shipper's complaint, the EUB will evaluate whether the rates being charged are just and reasonable and not unduly discriminatory. Although the predominant view is that the market will ensure that competitive rates are charged on oil pipelines, in the event the EUB proceeds to fully evaluate the rates being charged on the basis of a complaint, it would employ cost of service tolling methodology to assess the reasonableness of pipeline rates.

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 joint and several 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 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. 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.

On March 23, 2005, a release of approximately 3,400 barrels of crude oil occurred on Line 63 when it was severed as a result of a landslide caused by record rainfall in the Pyramid Lake area of Los Angeles County. Over the period March 2005 through June 2007, we expect to incur an estimated total of $25.6 million for oil containment and clean-up of the impacted areas, future monitoring costs, potential third-party claims and penalties, and other costs, excluding pipeline repair costs. As of December 31, 2005, we have incurred approximately $19.0 million of the total expected costs related to the oil release for work performed through that date. We estimate that $4.4 million of the remaining costs will be incurred in 2006 and $2.2 million will be incurred in 2007. Additionally, in 2005 we expensed $0.7 million for the repair of Line 63 and incurred $2.2 million of Line 63 capital improvements.

We have a pollution liability insurance policy with a $2.0 million deductible that covers containment and clean-up costs, third-party claims and penalties related to the Pyramid lake release. The insurance carrier has, subject to the terms of the insurance policy, acknowledged coverage of the incident and is processing and paying invoices related to the clean-up. We believe that, subject to the $2.0 million deductible, we will be entitled to recover substantially all of our clean-up costs and any third-party claims associated with the release. Our insurance coverage will not cover the cost to repair the pipeline, however, we have filed for a temporary tariff surcharge on Line 63 long-haul volumes to recover the insurance deductible and repair related costs of the release. As of December 31, 2005, we have recovered $12.3 million from insurance and recorded receivables of $11.3 million for insurance recoveries we deem probable, of which $2.2 million is classified as a long-term asset.

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.

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, (iii) in connection with the acquisition of the Pacific Terminals storage and pipeline distribution assets from Southern California Edison on July 31, 2003, we assumed certain environmental remediation costs, estimated at $2.7 million, and (iv) in connection with the Valero Acquisition on September 30, 2005, we assumed certain remediation costs estimated at $9.7 million. However, there is no guarantee that the actual remediation costs or associated liabilities will not exceed these amounts.

The assets that we acquired in the Valero Acquisition on September 30, 2005, were used for many years to distribute, store or transport petroleum products. There have been known releases of hazardous materials at almost all of the terminal sites and some of the pipeline rights-of-way, and most of these sites have or are presently undergoing remediation. We have assumed the risks associated with these environmental conditions, including the costs of remediation, subject only to a limited indemnity from the sellers of the Valero assets in the event of a breach of a seller warranty. Releases may also have occurred in the past at these properties that have not yet been discovered which could require additional future remediation. Although it is possible that the extent of the liability could be greater than we have estimated, we currently estimate that we will spend approximately $9.7 million to complete remediation activities for the Valero assets.

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 offense 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 $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 simple, on property under 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 27.5-acre property in Long Beach that we own in fee simple. 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 and PAT are on fee simple 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 simple in Casper, Wyoming. Our Evanston, Wyoming office and maintenance facility is occupied pursuant to a lease that expires on September 19, 2006, subject to a right to extend the lease for one additional year.

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 the 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, or leased, and (ii) 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. Our General Partner provides employees to conduct our U.S. operations. We and our General Partner collectively employ approximately 440 individuals who directly support our operations. We consider employee relations to be good. None of these employees are subject to a collective bargaining agreement, except for eight employees at our Paulsboro, New Jersey terminal, who are members of USW District 10-286 (Steel Workers), with whom we have a collective bargaining agreement that will end on October 1, 2009. 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.

ITEM 1A. Risk Factors

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 and refined products 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 gathering and marketing business;

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 and refined products 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 crude oil pipelines depends on the availability of attractively priced crude oil produced from the oil fields served by such 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 crude oil 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 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 crude oil 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.

We depend on refineries and petroleum products pipelines owned and operated by others to supply our refined products pipeline and terminals.

We depend on connections with refineries and petroleum products pipelines owned and operated by third parties as the primary source of supply for our refined products facilities. Outages at these refineries or reduced throughput on these pipelines because of testing, line repair, damage to pipelines, reduced operating pressures or other causes could result in our being unable to deliver products to our customers from our terminals or receive products for storage and could adversely affect our ability to meet our financial obligations and pay cash distributions.

If the refineries we serve process crude oil from locations to which our pipelines do not directly or indirectly connect, throughput on our crude oil 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 Alaskan North Slope 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 Alaskan North Slope 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 our Line 2000 and 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 crude oil 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 crude oil 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 crude oil 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 and refined products 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.

Terrorist attacks aimed at our facilities could adversely affect our business.

Since the September 11, 2001 terrorist attacks, the U.S. government has issued warnings that energy assets, specifically our nation's pipeline infrastructure, may be future targets of terrorist organizations. These developments have subjected our operations to increased risks. Any future terrorist attack that may target our facilities, those of our customers and, in some cases, those of other pipelines, could have a material adverse effect on our business.

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 May 2005, FERC issued a statement of general policy. According to the policy statement, a pipeline, including one organized as a partnership, can include in computing its cost of service an income tax allowance if the pipeline's owners have an actual or potential income tax liability on their income from the pipeline. FERC said it would determine on a case-by-case basis whether a particular partner has an actual or potential income tax liability and what assumptions should determine the related income tax rate. In December 2005, in a proceeding involving SFPP, L.P., FERC provided further clarification regarding the manner in which the income tax allowance policy statement would be applied to a pipeline owned by a partnership. Application of FERC's policy statement in individual cases may be subject to further FERC action or review in the appropriate Court of Appeals. Therefore, whether a partnership will ultimately be entitled to recover an income tax allowance in its cost of service is not certain. If we were required to defend our rates on a cost of service basis, whether because we filed new rates supported by a cost of service calculation or because a person claimed by complaint that our rates exceed a just and reasonable level, we would be required to establish pursuant to the new policy statement that the inclusion of an income tax allowance in our cost of service was just and reasonable. We can provide no assurance that we will be able to establish that our unitholders or our unitholders' owners are subject to United States federal income taxation on the income generated by us. If we are unable to do so, FERC could disallow a substantial portion of our income tax allowance, in which case it is likely that the level of maximum lawful rates would decrease from current levels.

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 business is subject to federal, state and local laws and regulations that govern the product quality specifications of the petroleum products that we store and transport.

Refined products that we store and transport are sold by our customers for consumption into the public market. Various federal, state and local agencies have the authority to prescribe specific product quality specifications to commodities sold into the public market. Changes in product quality specifications for refined products could reduce our throughput volume on our refined products pipelines and terminals, require us to incur additional handling costs or require the expenditure of capital. For instance, different product specifications for different markets impact the fungibility of the system and could require the construction of additional storage. If we are unable to recover these costs through increased revenues, our revenue and cash flows may be adversely affected, which could adversely affect our ability to make 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 and refined products 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 and refined pipelines could also be constructed in the areas served by our pipelines. Holly Energy Partners, L.P. and Enbridge Inc. have announced that they are studying a project for the construction of a pipeline that would transport crude oil from the terminus of the Frontier Pipeline to the Salt Lake City refineries, which, if constructed, would compete against certain of our Rocky Mountain pipelines. Competition among common carrier pipelines is based primarily on transportation charges, access to producing areas and refineries and customer demand for crude oil and refined products. We compete to a lesser extent with trucks that deliver crude oil and refined products 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 Business Unit Competition" and " Rocky Mountain Business Unit 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 gathering and marketing 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 or refined products 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 or refined products for many years. Crude oil, refined products 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, refined products 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 petroleum 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 and refined products 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. There can be no assurance that the actual remediation costs or associated liabilities will not exceed estimated amounts provided for, 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.

Actual costs incurred in connection with the release of crude oil on Line 63 in excess of our total estimated cost could have a material adverse effect on our financial condition, results of operations or cash flows.

The estimates of oil containment and clean-up of the areas impacted by the crude oil release on Line 63 are based on facts known at the time of estimation and our assessment of the ultimate outcome. Among the many uncertainties that impact the estimates are the necessary regulatory approvals for, and potential modification of, remediation plans, the ongoing assessment of the impact of soil and water contamination, changes in costs associated with environmental remediation services and equipment, and the possibility of third-party legal claims giving rise to additional expenses. Therefore, no assurance can be made that any costs incurred in excess of the total estimated cost for oil containment and clean-up of the impacted areas not covered by insurance, if any, would not have a material adverse effect on our financial condition, results of operations or cash flows.

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 transport and store crude oil and refined products. 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 2005, the following customers represented greater than 10% of transportation and storage revenue for our West Coast operations: BP America Production Company; Chevron; 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 pipeline transportation operations: Chevron 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 2006, 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, and (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.

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.

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.

LBMB controls 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 limited 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 26.6% of all the units representing limited partner interests (equivalent to 26.1% of the total limited and General Partner interests in the Partnership), our General Partner currently cannot be removed unless a sufficient number of other limited partners so act. 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 senior notes' indentures, and our revolving credit facility. An event of default under the indentures 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 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 revolving credit facility and/or declare all amounts payable by us under our 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.

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 indentures, and our revolving credit facility. An event of default under the indentures 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 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 revolving credit facility and/or declare all amounts payable by us under our 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 unitholders to sell their common units against their 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, unitholders may be required to sell their common units against their will and at an undesirable time or price and may not receive any return on their investment. Unitholders may also incur a tax liability upon a sale of their 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.

Unitholders' 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. Unitholders 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

- unitholders' right 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 principally in California, Colorado, Montana, New Jersey, Pennsylvania, South Dakota, Utah and Wyoming, 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 1B. Unresolved Staff Comments

None.

ITEM 3. Legal Proceedings

In August 2005, RPC learned that a Statement of Claim was filed by Desiree Meier and Robert Meier in the Alberta Court of Queen's Bench, Judicial District of Red Deer, naming RPC as defendant, and alleging personal injury and property damage caused by an alleged release of petroleum substances onto plaintiff's land by a prior owner and operator of the pipeline that is currently owned and operated by us. The claim seeks Cdn$1 million (approximately U.S.$0.9 million at December 31, 2005) in general damages, Cdn$2 million (approximately U.S.$1.7 million at December 31, 2005) in special damages, and, in addition, unspecified amounts for punitive, exemplary and aggravated damages, costs and interest. The Statement of Claim has not been served on RPC, so RPC has not been required to file an answer. RPC believes the claim is without merit, and intends to vigorously defend against it. RPC also believes that certain of the claims, if successfully proven by the plaintiffs, would be liabilities retained by the pipeline's prior owner under the terms of the agreement whereby we acquired the pipeline in question.

In connection with the Valero Acquisition, we assumed responsibility for the defense of a lawsuit filed in 2003 against Support Terminals Services, Inc., ("ST Services") by ExxonMobil Corporation ("ExxonMobil") in New Jersey state court. We have also assumed any liability that might be imposed on ST Services as a result of the suit. In the suit, ExxonMobil seeks reimbursement of approximately $400,000 for remediation costs it has incurred, from GATX Corporation, Kinder Morgan Liquid Terminals, the successor in interest to GATX Terminals Corporation, and ST Services. ExxonMobil also seeks a ruling imposing liability for any future remediation and related liabilities on the same defendants. These costs are associated with the Paulsboro, New Jersey terminal that was acquired by us on September 30, 2005. ExxonMobil claims that the costs and future remediation requirements are related to releases at the site subsequent to its sale of the terminal to GATX in 1990 and that, therefore, any remaining remediation requirements are the responsibility of GATX Corporation, Kinder Morgan and ST Services. We believe the claims against ST Services are without merit, and intend to vigorously defend against them.

We are involved in various other 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, liquidity 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 2005.

Part II

ITEM 5. Market Price for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities

Our common units are listed on the New York Stock Exchange under the symbol "PPX." At the close of business on December 31, 2005, we had 210 holders of record of our common units, representing approximately 22,000 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, 2005 and 2004 are as follows:

	Price Range			
	High	**Low**	**Cash Distribution Per Limited Partner Unit(1)**	**Payment Date**
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
Year ended December 31, 2005				
First Quarter 2005	33.65	28.00	0.5125	May 13, 2005
Second Quarter 2005	32.40	29.10	0.5125	August 12, 2005
Third Quarter 2005	35.69	31.07	0.5125	November 14, 2005
Fourth Quarter 2005	32.00	28.10	0.5550	February 14, 2006

(1) Distributions declared associated with each respective quarter.

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

We are party to credit agreements and indentures 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 Incurred in 2005."

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 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. On August 12, 2005, 25% of the then outstanding subordinated units (2,616,250 units) were converted to common units in accordance with the terms of our partnership agreement. Prior to the end of the subordination period, one-third of the remaining subordinated units, or an additional 2,616,250 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, 2006.

The early conversion 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.

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 each outstanding subordinated unit 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.

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.

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

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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	Above $0.4625 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%

In January 2006, the Partnership declared a cash distribution of $0.555 per limited partner unit for the fourth quarter of 2005, which was paid on February 14, 2006 to unitholders of record as of January 31, 2006. The fourth quarter 2005 distribution was the first quarterly distribution that exceeded $0.5125 per limited partner unit and, accordingly, the General Partner received an incentive distribution of approximately $255,000 in addition to its 2% interest distribution.

ITEM 6. Selected Financial Data

General

The following table shows selected financial and operating data of Pacific Energy Partners, L.P. (the "Partnership"), 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 Atlantic Terminals ("PAT"), which was formed for the purpose of acquiring the California and East Coast terminal assets we purchased on September 30, 2005 (see "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations Significant Developments in 2005");

(iv) Pacific Marketing and Transportation LLC ("PMT"), owner of the PMT gathering system and marketing business acquired on July 1, 2001;

(v) Rocky Mountain Pipeline System LLC ("RMPS"), owner of the Western Corridor and the Salt Lake City Core systems, and which acquired the West Pipeline System (now known as the Rocky Mountain Products Pipeline) on September 30, 2005, and;

(vi) Ranch Pipeline LLC ("Ranch"), the owner of a 22.22% partnership interest in Frontier Pipeline Company ("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. ("Aurora") and a partnership interest in Rangeland Pipeline Partnership ("Rangeland Partnership");

(ii) Rangeland Northern Pipeline Company ("RNPC"), which owns the remaining partnership interest in Rangeland Partnership; and

(iii) Rangeland Marketing Company ("RMC").

Rangeland Partnership owns all of the assets that make up the Rangeland pipeline system except the Aurora pipeline, which is owned by Aurora.

The Partnership also owns 100% of Pacific Energy Finance Corporation, which was organized for the purpose of co-issuing our senior notes.

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

The PT storage and distribution system was purchased on July 31, 2003 and is included in the financial and operating data after that date. The Rangeland system and the MAPL pipeline were purchased in May 2004 and June 2004, respectively, and both are included in the financial and operating data after those dates. PAT and Rocky Mountain Products Pipeline are included in the financial and operating data after their date of purchase on September 30, 2005.

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 performance 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; and (iii) 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 2005, 2004 and 2003. In July 2002, we completed our initial public offering of common units. Accordingly, distributable cash flow is not presented for 2002 and 2001. We believe that investors benefit from having access to the same financial measures being utilized by management. Distributable cash flow is a significant liquidity and performance measure used by our management to compare cash flows generated by the Partnership to the cash distributions we make to our partners. Using this financial measure, management can quickly compute the coverage ratio of these cash flows to cash distributions. 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 because the value of a partnership unit is in part measured by its yield (which in turn is based on the amount of cash distributions a partnership pays to its unitholders). 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 liquidity or 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. The generally accepted accounting measure most directly comparable to distributable cash flow is net cash provided by operating activities.

Several adjustments to distributable cash flow are required to reconcile to net cash provided by operating activities. These adjustments include: (i) adding back or subtracting net changes in operating assets and liabilities which are not included in distributable cash flow but are considered in net cash provided by operating activities; (ii) subtracting our share of Frontier's net income and adding distributions received from Frontier; (iii) adding the balance of the employee compensation under the long-term incentive plan since generally accepted accounting principles requires this common unit issuance to be presented on a gross basis; (iv) deducting transaction costs reimbursed by our General Partner which are required by generally accepted accounting principles to reduce net cash provided by operating activities; and (v) adding back sustaining capital expenditures which are not deducted in arriving at net cash provided by operating activities.

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."

	Year Ended December 31,				
	2005	2004	2003	2002	2001
	(in thousands, except per unit amounts)				
Consolidated Statements of Income:					
Revenue:					
Pipeline transportation(1)	$ 116,648	$ 108,395	$ 101,811	$ 103,090	$ 66,331
Storage and terminaling(2)	51,986	37,577	12,711		
Pipeline buy/sell transportation(3)	35,671	18,640			
Crude oil sales, net of purchases(4)	19,997	16,787	21,293	21,104	7,236
Total revenue before expenses	224,302	181,399	135,815	124,194	73,567
Expenses:					
Operating	104,397	85,286	61,046	57,817	34,252
General and administrative	18,472	15,400	13,705	7,515	2,787
Accelerated long-term incentive plan compensation expense	3,115				
Line 63 oil release costs	2,000				
Transaction costs	1,807				
Rate case litigation expense(5)					1,853
Depreciation and amortization	29,406	24,173	18,865	15,919	11,368
Total expenses	159,197	124,859	93,616	81,251	50,260
Share of net income (loss) of Frontier:					
Income before rate case and litigation expense	1,757	1,328	1,459	1,904	1,569
Rate case and litigation expense			(1,621)	(557)	
Share of net income (loss) of Frontier(6)	1,757	1,328	(162)	1,347	1,569
Write-down of idle property(7)	(450)	(800)			
Operating income	66,412	57,068	42,037	44,290	24,876
Interest and other income	1,119	1,032	479	918	787
Write-off of deferred financing cost and interest rate swap termination expense		(2,901)			
Interest expense	(26,720)	(19,209)	(17,487)	(11,634)	(10,056)
Income before income taxes	40,811	35,990	25,029	33,574	15,607
Income tax (expense) benefit:					
Current	(1,252)	(326)			
Deferred	89	65			
	(1,163)	(261)			
Net income	$ 39,648	$ 35,729	$ 25,029	$ 33,574	$ 15,607
Basic net income per limited partner unit(8)	$ 1.25	$ 1.23	$ 1.10	$ 0.55	$
Diluted net income per limited partner unit(8)	$ 1.25	$ 1.23	$ 1.09	$ 0.55	$
Weighted average limited partner units outstanding(8):					
Basic	32,381	28,406	22,328	20,930	

	Year Ended December 31,				
Diluted	32,414	28,488	22,540	20,930	
Other Financial Data:					
EBITDA(9)	$ 96,937	$ 79,372	$ 61,381	$ 61,127	$ 37,031
Distributable Cash Flow(10)	68,831	63,399	44,972		
Net cash provided by operating activities	76,108	57,226	42,723	45,793	26,406
Net cash used in investing activities	(512,751)	(155,952)	(180,332)	(101,311)	(37,203)
Net cash provided by financing activities	431,280	112,410	123,435	69,880	8,044
Capital expenditures:					
Sustaining	$ 6,067	$ 1,953	$ 2,149	$ 2,725	$ 3,381
Transition	11,401	1,874	351	2,039	
Expansion	34,249	12,693	8,392	878	2,433
Total capital expenditures	$ 51,717	$ 16,520	$ 10,892	$ 5,642	$ 5,814

	Year Ended December 31,				
	2005	2004	2003	2002	2001
	(in thousands)				
Balance Sheet Data (at period end):					
Property and equipment, net	$ 1,185,534	$ 718,624	$ 567,954	$ 404,842	$ 309,675
Total assets	1,476,452	869,905	650,203	487,038	372,179
Total debt, including current portion	565,632	357,163	298,000	225,000	181,333
Net partners' capital (net parent investment)	698,239	422,466	295,067	215,267	157,361
Limited partner units outstanding(8)	39,298	29,624	24,907	20,930	
Operating Data:					
West Coast Business Unit:					
Pipeline throughput (mbpd)(11)	119.6	141.2	151.0	162.8	158.0
Rocky Mountain Business Unit throughput (mbpd)(11):					
Rangeland system:					
Sundre North(3)	21.0	21.0			
Sundre South	47.1	48.1			
Western Corridor system(1)	24.7	20.2	16.7	15.0	
Salt Lake City Core system(1)	119.6	115.1	107.5	115.6	41.1
Rocky Mountain Products Pipeline(1)	60.2				
Frontier pipeline(13)	47.3	47.4	41.7	44.4	40.5

(1) Includes our ownership of the Western Corridor and Salt Lake City Core systems from March 1, 2002 and our ownership of the Rocky Mountain Products Pipeline acquired on September 30, 2005.

(2) Includes our ownership of the Pacific Terminals storage and distribution system from July 31, 2003 and our ownership of Pacific Atlantic terminals from September 30, 2005.

(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 $623,115, $402,283, $358,454, $316,283, and $160,085 for 2005, 2004, 2003, 2002 and 2001, respectively.

(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) On December 17, 2001, Pacific Energy (Predecessor) acquired an additional 9.72% partnership interest in Frontier. Therefore, 2001 includes 12.5% of the net income of Frontier 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.

(7) These amounts represent write-downs 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:

	Year Ended December 31,				
	2005	2004	2003	2002	2001

	Year Ended December 31,				
	(in thousands)				
Net income	$ 39,648	$ 35,729	$ 25,029	$ 33,574	$ 15,607
Interest expense	26,720	19,209	17,487	11,634	10,056
Depreciation and amortization	29,406	24,173	18,865	15,919	11,368
Income tax expense	1,163	261			
EBITDA	$ 96,937	$ 79,372	$ 61,381	$ 61,127	$ 37,031

Interest income of $744, $209, $156, $385 and $320 for each of the five years ended December 31, 2005, 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 and 2001. A reconciliation from reported net income to distributable cash flow and to net cash provided by operating activities for the years ended December 31, 2005, 2004 and 2003 is as follows:

	Year Ended December 31,		
	2005	2004	2003
		(in thousands)	
Net income	$ 39,648	$ 35,729	$ 25,029
Depreciation and amortization	29,406	24,173	18,865
Amortization of debt issue costs and accretion of discount on long-term debt	2,027	1,537	1,028
Non-cash employee compensation under long-term incentive plan	1,429	857	2,199
Write-off of deferred financing cost		2,321	
Write-down of idle property	450	800	
Loss on disposal of idle property	220		
Transaction costs	1,807		
Deferred income tax benefit	(89)	(65)	
Sustaining capital expenditures	(6,067)	(1,953)	(2,149)
Distributable cash flow	**68,831**	**63,399**	**44,972**
Less net (increase) decrease in operating assets and liabilities	2,000	(7,973)	(7,349)
Less share of income of Frontier (add share of loss of Frontier)	(1,757)	(1,328)	162
Add net distributions from Frontier (deduct contributions to Frontier)	1,317	(44)	1,755
Less non-cash employee compensation under long-term incentive plan added (deducted) above	(1,429)	(857)	(2,199)
Employee compensation under long-term incentive plan	2,886	2,076	3,233
Less transaction costs	(1,807)		
Add sustaining capital expenditures	6,067	1,953	2,149
Net cash provided by operating activities	$ 76,108	$ 57,226	$ 42,723
General Partner interest in distributable cash flow	$ 2,049	$ 1,764	$ 899
Limited partner interest in distributable cash flow	66,782	61,635	44,073
Total distributable cash flow	$ 68,831	$ 63,399	$ 44,972
Weighted average diluted limited partner units outstanding	32,414	28,488	22,540

(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.

(13)

Represents 100% of the throughput on the 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. 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 financial data included herein reflects (i) the ownership and results of operations of the assets comprising the Pacific Terminals ("PT") storage and distribution system for the period from July 31, 2003; (ii) the ownership and results of operations of the Rangeland system for the period from May 11, 2004; (iii) the ownership of the MAPL pipeline for the period from June 30, 2004; and (iv) the ownership of the Pacific Atlantic Terminals and Rocky Mountain Products Pipeline assets for the period from September 30, 2005. 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, refined products and other related products. We generate revenue primarily by transporting such commodities on our pipelines, by leasing capacity in our storage tanks, and by providing other terminaling services. We also buy and sell crude oil, activities that are generally complementary to our other crude oil operations. We conduct our business through two business units, the West Coast Business Unit, which includes activities in California and the Philadelphia, Pennsylvania area, and the Rocky Mountain Business Unit, which includes activities in five Rocky Mountain states and Alberta, Canada.

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 "Significant Developments in 2005" below. References 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.

Our West Coast Business Unit consists of (i) Line 2000, (ii) the Line 63 system, (iii) the Pacific Terminals storage and distribution system, (v) the PMT gathering system and crude oil marketing activities, and (iv) Pacific Atlantic Terminals, which was acquired on September 30, 2005 (see "Significant Developments in 2005 Acquisition of Assets from Valero, L.P."). Line 2000 and Line 63 are the only common carrier pipelines delivering crude oil produced in the San Joaquin Valley and the two primary California Outer Continental Shelf producing fields, Point Arguello and Santa Ynez, to the Los Angeles Basin and Bakersfield. The Pacific Terminals storage and distribution system is a crude oil and dark products storage and pipeline distribution system servicing the Los Angeles Basin, and the PMT gathering system is a proprietary gathering operation in the San Joaquin Valley. We have integrated the recently acquired San Francisco area terminals and Philadelphia area terminals ("Pacific Atlantic Terminals") with our existing West Coast Business Unit, and we are currently seeking permits for the development of 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) the Rangeland system, (ii) certain undivided interests in the Western Corridor system, (iii) the Salt Lake City Core system, (iv) our interest in Frontier Pipeline Company, and (v) the Rocky Mountain Products Pipeline, which was acquired on September 30, 2005 (See "Significant Developments in 2005 Acquisition of Assets from Valero, L.P.). Our Rocky Mountain crude oil 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 through our Rangeland system. Deliveries of crude oil are made to refineries directly through our pipelines or indirectly through connections with third-party pipelines. The Rocky Mountain Products Pipeline supplies refined products to the South Dakota, Wyoming and Colorado markets.

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 and terminaling 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 and 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, which will generally not expire until after June 30, 2007, subject to early termination under certain conditions, 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 for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities" regarding subordinated units and the subordination period.

Significant Developments in 2005

Acquisition of Assets from Valero, L.P.

On September 30, 2005, we completed the purchase of certain terminal and pipeline assets (the "Valero Acquisition") from Support Terminals Operating Partnership, L.P., Kaneb Pipe Line Operating Partnership, L.P. and Shore Terminals LLC (the "Sellers") for an aggregate purchase price of $455.0 million, plus $11.5 million for the assumption of certain environmental and operating liabilities and $3.7 million for closing costs. Valero, L.P. was required to divest these assets pursuant to an order from the Federal Trade Commission in connection with its acquisition of the Kaneb group of companies. The purchased assets consist of (i) the Martinez terminal and Richmond terminal in the San Francisco, California area, (ii) the North Philadelphia and South Philadelphia terminals and the

Paulsboro, New Jersey terminal in the Philadelphia, Pennsylvania area, and (iii) a 550-mile refined products pipeline with four terminals in the U.S. Rocky Mountains (collectively the "Valero Assets").

The Martinez and Richmond terminals currently have 4.1 million barrels of combined storage capacity. The terminals handle refined products, blend stocks and crude oil, and are connected to a network of owned and third-party pipelines that carry crude oil and light products to and from area refineries. These terminals also receive and deliver crude oil and light products by marine vessel or barge. The Richmond terminal has a rail spur for delivery and receipt of light products and a truck rack for product delivery.

The North Philadelphia, South Philadelphia and Paulsboro, New Jersey terminals handle refined products and have a combined storage capacity of 3.1 million barrels. The terminals receive product via connections to third-party pipelines and have truck racks for deliveries. The North Philadelphia and Paulsboro terminals can also deliver and receive products by marine vessel or barge.

The Rocky Mountain Products Pipeline, formerly known as the West Pipeline System, consists of 550 miles of pipeline extending from Casper, Wyoming east to Rapid City, South Dakota and south to Colorado Springs, Colorado. There are products terminals at Rapid City, South Dakota, Cheyenne, Wyoming and Denver and Colorado Springs, Colorado with a combined storage capacity of 1.7 million barrels. The pipeline system has various segments with different receipt and delivery points.

We have integrated the operations, maintenance, marketing and business development of the Rocky Mountain Products Pipeline with our existing pipeline activities in the Rocky Mountain Business Unit. Similarly, we have integrated the San Francisco area and Philadelphia area terminals with our existing pipeline and terminal activities in our West Coast Business Unit.

We funded the Valero Acquisition through a combination of proceeds from a private placement of 4.3 million common units, a public equity offering of 5.2 million common units, a private placement of $175.0 million of senior unsecured notes, and borrowings under our new revolving credit facility (see below for a discussion of these new financing arrangements).

Equity and Debt Offerings

On September 14, 2005, we sold 4,550,000 common units at a public offering price of $32.00 per unit. On September 16, 2005, the underwriters exercised their over-allotment option and purchased an additional 682,500 common units at the same price. Net proceeds from the offering and exercise of the underwriters option, including the General Partner's contribution of $3.4 million, totaled approximately $163.2 million after deducting underwriting fees and offering expenses of $7.6 million. We used net proceeds from the equity offering to partially fund the Valero Acquisition.

On September 23, 2005, we completed the sale of $175.0 million of $6^1/_4$% senior unsecured notes due September 15, 2015. The notes were sold in a private offering to qualified institutional buyers in reliance on Rule 144A under the Securities Act of 1933 ("Securities Act") and to non-U.S. persons under Regulation S of the Securities Act of 1933. The notes were sold for 99.544% of face value resulting in an effective interest rate of 6.3125% to maturity. Net proceeds of $170.9 million from the sale of the notes, after deducting $0.8 million discount and offering expenses of $3.3 million, were used to partially fund the Valero Acquisition. In January 2006, the 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.

On September 30, 2005, we sold 4,300,000 units pursuant to a Common Unit Purchase Agreement with certain institutional investors at a price of $30.75 per unit. We received net proceeds of $131.8 million from the sale of the common units, including the General Partner's contribution of $2.7 million, which were used to partially fund the Valero Acquisition. We filed a registration statement in December 2005 with the Securities and Exchange Commission ("SEC") which allows for the resale by the investors from time to time of the privately placed common units.

New Revolving Credit Facility

On September 30, 2005, we entered into a new five-year $400 million senior secured revolving credit facility (the "New Credit Facility") that replaced our previous U.S. and Canadian revolving credit facilities. The New Credit Facility is available for general partnership purposes in the U.S. and Canada, including working capital, letters of credit and distributions to unitholders (subject to certain limitations). The New Credit Facility matures on September 30, 2010, and we may prepay all loans under the New Credit Facility without premium or penalty. Obligations under the New Credit Facility are guaranteed by all of our subsidiaries except those for which regulatory approval is required and are secured by substantially all of our assets, excluding property held by the non-guaranteeing subsidiaries. The New Credit Facility is recourse to us and the guarantors, but non-recourse to our General Partner.

Included in the New Credit Facility is a Canadian sub-facility. The Canadian sub-facility currently has a limit of U.S.$100 million, but can be adjusted from time to time by us. The Canadian sub-facility includes an option for us to receive loans in either U.S. dollars or Canadian dollars.

Purchase of Crude Oil and Contracts

On July 1, 2005, we through our Pacific Marketing and Transportation ("PMT") subsidiary purchased certain crude oil contracts and crude oil inventories for approximately $3.8 million plus contingent payments to be measured over the period from July 1, 2005 through December 31, 2008 based on specified performance criteria.

Line 63 Crude Oil Release

On March 23, 2005, a release of approximately 3,400 barrels of crude oil occurred on Line 63 when it was severed as a result of a landslide caused by heavy rainfall in the Pyramid Lake area of Los Angeles County. We expect to incur an estimated total of $25.6 million for oil containment and clean-up of the impacted areas, future monitoring costs, potential third-party claims and penalties, and other costs, excluding pipeline repair costs. As of December 31, 2005, we had incurred approximately $19 million of the total expected costs related to the oil release for work performed through that date. We estimate that $4.4 million of the remaining costs will be incurred in 2006 and $2.2 million will be incurred in 2007.

We have a pollution liability insurance policy with a $2.0 million deductible that covers containment and clean up costs, third-party claims and penalties. The insurance carrier has, subject to the terms of the insurance policy, acknowledged coverage of the incident and is processing and paying invoices related to the clean-up. Although we believe we are entitled, subject to the $2.0 million deductible, to recover substantially all of our clean-up costs and third-party claims associated with the release, we can make no assurance that this will be the case. As of December 31, 2005, we have recovered $12.3 million from the insurance carrier and recorded receivables of $11.3 million for insurance recoveries we deem probable, of which $2.2 million is considered long-term. As new information becomes available in future periods, our initial estimates of costs and recoveries may change.

We recorded $2.0 million in net costs in "Line 63 oil release costs" in the accompanying consolidated statements of income for the year ended December 31, 2005. The $2.0 million net oil release costs reflects the per-occurrence deductible under that coverage and consists of $25.6 million of total anticipated costs relating to the release, less insurance recoveries and accrued insurance receipts.

During the time the pipeline was out of service, we transferred significant volumes of light crude oil, on a temporary basis, from Line 63 to Line 2000, to mitigate the impact on customers and limit the potential loss of revenue. We also asked our customers to shift volumes of Outer Continental Shelf crude oil from Line 63 to Line 2000. The permanent repair of Line 63 was completed in October 2005. We expensed $0.7 million, all in the second quarter, for the repair of Line 63 and incurred $2.2 million of Line 63 capital improvements in the third and fourth quarters of 2005.

Effective August 1, 2005, with the approval of the California Public Utilities Commission (the "CPUC"), we began collecting a temporary surcharge of $0.10 per barrel on our Line 63 long-haul tariff rates to recover our uninsured costs relating to this release together with costs incurred or to be incurred as a result of other problems caused to Line 63 by rain-related earth movement and stream erosion during the 2004-2005 winter. We were required under the terms of the CPUC decision that approved the collection of the surcharge to substantiate in a subsequent advice letter filing with the CPUC that the actual costs incurred by us were necessary and reasonable and otherwise recoverable. PPS filed its advice letter filing on January 27, 2006, which was approved by the CPUC on February 22, 2006.

Sale of The Anschutz Corporation's Interest in Us

On March 3, 2005, The Anschutz Corporation completed the sale of its 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. 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 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. 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 Pacific Energy GP, Inc. prior to the LB Acquisition. PEM also adopted Pacific Energy GP, Inc.'s governance guidelines and its compensation structure and employee benefits plans and policies.

Pursuant to an Ancillary Agreement entered into in connection with the LB Acquisition, LBP and The Anschutz Corporation reimbursed us $2.4 million, which represents the cost incurred by us in connection with a consent solicitation prepared and delivered to the holders of our $7^1/_8$% senior notes, due 2014 to approve certain amendments to the governing indenture, and for severance and other costs incurred in connection with the sale of our General Partner. In accordance with generally accepted accounting principles we recorded $0.6 million of the costs as capitalized deferred financing costs and $1.8 million as an expense. The reimbursements were recorded as the General Partner's capital contribution.

Additionally, in connection with the change in control of our General Partner, all restricted units outstanding under the Long-Term Incentive Plan immediately vested pursuant to the terms of the grants. As a result, we issued 99,583 common units and recorded a compensation expense of $3.1 million.

Business Fundamentals

Pipeline Transportation

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

Our shippers determine the amount of crude oil and refined products we transport on our pipelines, but we can 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 tariff rates we charge on Line 2000 and the Line 63 system are regulated by 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 crude oil pipelines are regulated by either the FERC or the Wyoming Public Service Commission, generally under a cost-of-service approach. The FERC, Wyoming PSC, and the Colorado PUC each regulate various tariffs on the Rocky Mountain Products Pipeline.

Although the tariff rates we charge on the system are regulated, competitive forces may also limit the amount of our filed rates. The FERC tariff rates are generally adjusted, effective July 1 of each year, by the amount of change in the Producer Price Index for Finished Goods.

Following are recent tariff rate increases on our pipelines:

- Effective August 1, 2005, we implemented a temporary surcharge of $0.10 per barrel on our Line 63 long-haul tariff rates to recover our costs relating to the oil release (see "Line 63 Crude Oil Release" above) together with other costs incurred or to be incurred as a result of rain-related earth movement and stream erosion.

- On July 1, 2005, we increased the FERC tariff rates on our U.S. Rocky Mountain crude oil pipelines by 3.6% based on the FERC index adjustment.

- On May 1, 2005 we increased the tariff rates on our Line 2000 by approximately 4.8%.

- 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 rate increases on our West Coast pipelines partially mitigate the impact of declining throughput.

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 Outer Continental Shelf, total production is generally declining.

In the Rocky Mountains, our pipelines are connected to Canadian sources of crude oil, and in 2004 we completed the acquisition of the Rangeland system in Alberta, giving us greater access to significant supplies of Canadian crude oil, including synthetic crude oil, which we believe will replace any long term U.S. Rocky Mountain production declines and meet growing demand in the U.S. Rocky Mountain region. Our initiating pump station in Edmonton, as well as a connection to a third-party pipeline providing access to synthetic crude oil, was completed in March 2006. It appears in recent months that production in the U.S. Rocky Mountains may be increasing with the increased amount of natural gas related drilling, which results in increased volumes of crude oil and condensate. We believe, however, that the longer term production of crude oil in the U.S. Rocky Mountains will resume its historical decline.

The Rocky Mountain Products Pipeline (formerly the West Pipeline System) acquired from Valero in 2005 is a common carrier petroleum products pipeline and terminals network. The system generates revenues through transportation tariffs for volumes of petroleum products it ships. These tariffs vary depending upon where the product originates and, where ultimate delivery occurs. All transportation rates are market-based rates or published tariffs filed with the FERC and other state agencies. The products terminals on the pipeline system also earn revenues by providing additional services.

Storage and Terminaling

We provide storage and terminaling services to refineries in the Los Angeles Basin and San Francisco areas in California and in the Philadelphia, Pennsylvania area. The fundamental items impacting our storage and terminaling 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 other 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 are currently completing one such tank conversion. While PT's rates are subject to regulation by the CPUC, the CPUC has allowed PT to establish rates based on market conditions through negotiated contracts.

The Martinez, Richmond, Paulsboro and Philadelphia terminals that we purchased from Valero are refined product (and, in the case of Martinez, crude oil) storage and terminaling facilities that generate revenues primarily from fees that we charge customers for storage, throughput and other services. Demand for refined products storage capacity, mostly at the Philadelphia area terminals, depends on connections with refineries and petroleum products pipelines owned and operated by third parties.

Demand for refined products storage at our San Francisco area terminals tends to be stable over time as most of their lease contracts are evergreen contracts for a year or more. Additionally, the San Francisco area terminals are not overly reliant on local area refinery production to satisfy their supply of refined products. The San Francisco area terminals receive a significant amount of their supplies from imported refined products into the San Francisco harbor. The Martinez terminal is permitted for an additional 1.3 million barrels of storage capacity and one of our goals is to increase its storage capacity. We have begun construction of three 150,000 barrel tanks which we expect to place in service in July 2006.

The throughput service business of our Philadelphia area terminals, which receive products from local refineries, the U.S. Gulf Coast and New York Harbor is dependent on the demand for gasoline and other products in the Philadelphia market. In addition, our Philadelphia area terminals provide storage services for local refineries and other marketers.

Pipeline Buy/Sell Transportation

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.

We are making significant changes to the revenue-generating capability of the Rangeland system by (i) combining and fully integrating all of our Canadian and U.S. Rocky Mountain pipeline assets under common management, (ii) establishing connections with other pipelines, thereby expanding the throughput capacity of the Rangeland system, and (iii) constructing a pump station and receiving terminal in Edmonton, Alberta. Following completion of our Edmonton, Alberta initiation station in March 2006, 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 two of our subsidiaries, Rangeland Marketing Company ("RMC") and Rangeland Pipeline Partnership, 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 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; or (ii) sell product to RMC at the inlet to the pipeline without repurchasing product from RMC.

Virtually all of the pipelines that comprise the Rangeland system are subject to the jurisdiction of the Alberta Energy and Utilities Board ("EUB"). A short segment of the Rangeland system that connects to the Western Corridor system at the U.S.-Canadian border is subject to the jurisdiction of 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 relating to transportation rates.

Effective December 1, 2005, we increased the location differentials on the Rangeland pipeline by an average of 6.9%.

Gathering Activities and Marketing Business

Through our Pacific Marketing and Transportation ("PMT") subsidiary, we purchase, gather, and resell crude oil, principally in California's San Joaquin Valley and in the Rocky Mountain area in the vicinity of our pipelines. In the third quarter of 2005, we began selectively purchasing and reselling crude oil in other areas as well, although this is not a primary focus.

In California, our PMT gathering system is a proprietary intrastate operation that is not regulated by the CPUC or the FERC. It is complementary to our pipeline transportation business. The California gathering network effectively extends our pipeline network to capture supplies of crude oil bound for transportation to Los Angeles that might not otherwise be shipped through our pipelines. In the U.S. and Canadian Rocky Mountain area, PMT facilitates transportation on our Canadian and U.S. Rocky Mountain pipelines by purchasing crude oil from Canada for resale in Rocky Mountain marketplaces.

The contribution of our PMT gathering 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 that PMT buys for use in its gathering operations, and the price of the crude oil it sells. Costs and sales prices are generally impacted by crude oil prices, 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 another price basis. Finally, it varies with the volumes gathered. 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.

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. In 2006, we have a $106 million expansion capital budget as detailed in "Liquidity and Capital Resources Capital Requirements" below. We also intend to expand, principally by acquisition, into the 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

Many of our operating expenses, including the cost of field and support personnel, maintenance, control systems, telecommunications, rights-of-way and insurance, are relatively fixed and vary little with changes in throughput. Certain of our costs, however, do vary with throughput, the most material being the cost of power used to operate 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 oil or product release to the extent they are not covered by insurance, and repairs caused by severe weather as we experienced in California and Alberta, Canada in 2005.

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 440 individuals who directly support our operations. We consider employee relations to be good. None of these employees are subject to a collective bargaining agreement, except for eight employees at our Paulsboro, New Jersey, terminal, who are members of USW District 10-286 (Steel Workers), with whom we have a collective bargaining agreement that will end on October 1, 2009. 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 each 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. We have entered into certain foreign exchange contracts to mitigate currency exchange risks (see "Item 7A Quantitative and Qualitative Disclosures about Market Risk").

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 reported during each 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 2-Summary of Significant Accounting Policies" to our accompanying 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 (including environmental remediation liabilities). Additionally, we must determine whether an acquisition is to be treated as a purchase of a business or a set of net assets because excess purchase price is only allocated to goodwill in a business combination. Determination 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 and amortization expense we subsequently record. The principal assets we have acquired to date are property, pipelines, storage tanks and equipment, as well as intangible assets such as customer relationships and contractual rights.

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 may use outside environmental consultants to assist us in making these estimates. We also are required to estimate the amount of any probable recoveries, including insurance recoveries. In addition, generally accepted accounting principles require us to establish liabilities for the costs of asset retirement obligations when a legal or contractual obligation exists to dispose of or restore an asset upon its retirement and the timing and cost of such work is reasonably estimable. We will record such liabilities only when such timing and costs are reasonably determinable.

From time to time, a shipper or group of shippers or regulatory body may initiate regulatory proceedings or other actions 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 operations, our Canadian operations, any inventory earned through our tariffs for the transportation of crude oil in our common carrier pipelines and any inventory of refined products at our terminals is carried in our accounts at the lower of cost or market value, unless it is hedged, in which case it is carried at market. On any unhedged portion, we are exposed to the potential for a write-down to market value. To the extent we owe our customers crude oil or refined products, we are exposed to the potential of additional costs in the event market prices increase.

Results of Operations

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. We have provided a reconciliation of net income to the results of our operations, excluding those unusual items, in our analyses below. Following is a description of each of the unusual items that impacted the results of our operations.

Oil release on Line 63. As a result of the March 23, 2005 release of crude oil from our Line 63, we recorded $2.0 million net oil release costs in the first quarter of 2005, consisting of what we now estimate to be $25.6 million of accrued costs relating to the release, net of insurance recovery of $12.3 million and accrued insurance receipts of $11.3 million. The discussion in "Significant Developments in 2005" describes the nature of these estimates and the potential for these estimates to increase or decrease in future periods.

Accelerated long-term incentive plan compensation expense. In March 2005, in connection with the change in control of our General Partner, all restricted units outstanding under the Long-term Incentive Plan immediately vested. As a result, we recognized $3.1 million in compensation expense in the first quarter of 2005.

Transaction costs. Pursuant to an Ancillary Agreement entered into in connection with the LB Acquisition, LBP and The Anschutz Corporation reimbursed us $2.4 million for the cost incurred in connection with a consent solicitation prepared and delivered to the holders of our $7^1/_8$% senior notes to approve certain amendments to the governing indenture and for severance and other costs incurred in connection with the sale of our General Partner. In accordance with generally accepted accounting principles, we recorded $0.6 million as capitalized deferred financing costs and $1.8 million as an expense, both in the first quarter of 2005. The reimbursements were recorded as a capital contribution to the Partnership by our General Partner.

Write-down of idle property. We recorded $0.5 million and $0.8 million for the write-down of idle property associated with idle Pacific Terminals properties in 2005 and 2004, respectively.

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

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.

Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

Summary

Net income for the year ended December 31, 2005 was $39.6 million or $1.25 per diluted limited partner unit compared to $35.7 million or $1.23 per diluted limited partner unit for 2004.

Net income for the year ended December 31, 2005 reflects the benefit of a full year of operations for the Rangeland system, acquired in May 2004, and the acquisition of the Rocky Mountain Products Pipeline and the San Francisco and Philadelphia area terminals on September 30, 2005.

Following is a reconciliation of net income to the results of our operations, excluding unusual items mentioned above:

	Year ended December 31,			
	2005	2004	Change	Percent
	(In thousands)			
Net income	$ 39,648	$ 35,729	$ 3,919	11%
Add: Line 63 oil release costs	2,000		2,000	
Accelerated long-term incentive compensation expense	3,115		3,115	
Transaction costs	1,807		1,807	
Write-off of deferred financing cost and interest rate swap termination expense		2,901	(2,901)	
Write-down of idle property	450	800	(350)	(44)
	$ 47,020	$ 39,430	$ 7,590	19%

The improvement in the results of operations, excluding the effect of the unusual items mentioned above, reflects the benefit of (i) the operations of the Rangeland system acquired in May 2004, (ii) the operations of the Rocky Mountain Products Pipeline and the San Francisco and Philadelphia area terminals acquired on September 30, 2005, (iii) higher pipeline transportation revenues on the Rocky Mountain pipelines, (iv) higher margins and new contracts at PMT, and (v) higher storage and distribution revenues on our Pacific Terminal systems. Partially offsetting these increases were lower West Coast pipeline volumes, repairs and maintenance associated with earth movement and stream erosion problems caused by the record rainfall in Southern California and Alberta, Canada, and repair of two Pacific Terminals storage tanks.

There were 32.4 million weighted average limited partner units outstanding in the year ended December 31, 2005, approximately 14% more limited partner units than the 28.5 million weighted average units outstanding in the year ended December 31, 2004, primarily due to the sale in September 2005 of additional common units to partially fund the acquisition of the Valero Assets on September 30, 2005.

Segment Information

The following is a discussion of segment operating income, excluding the unusual items mentioned above. Segment operating income does not include general and administrative expenses, accelerated long-term incentive compensation plan expense and transaction costs as these items are not allocated to the West Coast and Rocky Mountain Business Units.

	Year ended December 31,			
West Coast	2005	2004	Change	Percent
	(In thousands)			
Operating income	$ 50,337	$ 48,739	$ 1,598	3%
Add: Line 63 oil release costs	2,000		2,000	
Write-down of idle property	450	800	(350)	(44)
	$ 52,787	$ 49,539	$ 3,248	7%
Operating data:				
Pipeline throughput (bpd)	119.6	141.2	(21.6)	(15)%

West Coast operating income, after excluding the unusual items in the table above, was $52.8 million in 2005 compared to $49.5 million in 2004. West Coast operating income primarily increased because of (i) the acquisition of the San Francisco and Philadelphia area terminals on

September 30, 2004 (ii) higher PT storage and distribution revenue because of higher tank utilization and increased storage capacity, and (iii) the acquisition of new contracts and higher margins on PMT. Partially offsetting these increases were (i) reduced volumes on our West Coast pipelines caused by Los Angeles area refinery maintenance and lower San Joaquin Valley and Outer Continental Shelf production, resulting in lower volumes moving south to Los Angeles, (ii) $2.8 million of repairs and maintenance associated with earth movement and stream erosion problems caused by record rainfall in Southern California, and (iii) unscheduled repairs of two Pacific Terminals storage tanks. The revenue effect of lower volumes was partially offset by incremental revenue from increased tariffs on Line 63 beginning November 1, 2004, on Line 2000 beginning May 1, 2005, and on Line 63 beginning August 2005 from a temporary surcharge to recover the rain-related repair costs and our Line 63 oil release costs.

	Year ended December 31,			
Rocky Mountain Business Unit	**2005**	**2004**	**Change**	**Percent**
		(In thousands)		
Operating income	$ 39,469	$ 23,729	$ 15,740	66%
Operating data (bpd):				
Rangeland pipeline system:				
Sundre North	21.0	21.0		
Sundre South	47.1	48.1	(1.0)	(2)
Western Corridor system	24.7	20.2	4.5	22
Salt Lake City Core system	119.6	115.1	4.5	4
Rocky Mountain Products pipeline	60.2		60.2	
Frontier pipeline	47.3	47.4	(0.1)	(1)

For the year ended December 31, 2005, Rocky Mountain operating income was $39.5 million, compared to $23.7 million for the year ended December 31, 2004. The increase included a full year results of the Rangeland system, which was acquired in 2004, and the results of the Rocky Mountain Products Pipeline, which was acquired on September 30, 2005. In addition, increased market share for pipeline shipments of crude oil to Billings, Montana, and increased demand by the Salt Lake City, Utah refineries, helped drive higher pipeline volumes on the U.S. Rocky Mountain systems.

Statement of Income Discussion and Analysis

	Year ended December 31,			
Revenue	**2005**	**2004**	**Change**	**Percent**
		(In thousands)		
Pipeline transportation revenue	$ 116,648	$ 108,395	$ 8,253	8%
Storage and terminaling revenue	51,986	37,577	14,409	38
Pipeline buy/sell transportation revenue	35,671	18,640	17,031	91
Crude oil sales, net of purchases:				
Crude oil sales	643,112	419,070	224,042	53
Crude oil purchases	(623,115)	(402,283)	220,832	55
Crude oil sales, net of purchases	19,997	16,787	3,210	19
Net revenue before expenses	$ 224,302	$ 181,399	$ 42,903	24%

Pipeline transportation revenue increased in 2005 because of higher volumes on our U.S Rocky Mountain pipelines and the acquisition of the Rocky Mountain Products pipeline on September 30, 2005. Volumes on the U.S. Rocky Mountain pipelines were higher due to increased demand by refineries in Billings, Montana, Casper, Wyoming and Salt Lake City, Utah. This increase was partially offset by lower West Coast pipeline revenues due to natural field production decline. Increased tariffs helped to partially offset lower West Coast pipeline volumes.

Storage and terminaling revenue includes the operations of the San Francisco and Philadelphia area terminals acquired in the Valero Acquisition. Additionally, revenue on our Pacific Terminals storage and distribution system was higher because of higher tank utilization and increased storage capacity being made available as a result of a 72,000 barrel idle tank being put into operation during the third quarter of 2004.

The increase in pipeline buy/sell transportation revenues of $17.0 million reflects a full year operations of the Rangeland system, which was acquired in May 2004, as well as an increase in location differentials effective December 1, 2004.

Crude oil sales net of purchases increased because of the purchase of crude oil contracts on July 1, 2005 and higher margins. In addition, higher oil prices increased gross sales and purchases values. We consider this activity to generally be complementary to our pipeline transportation operations.

	Year ended December 31,			
Expenses	**2005**	**2004**	**Change**	**Percent**
	(In thousands)			
Operating expenses	$ 104,397	$ 85,286	$ 19,111	22%
General and administrative expense	18,472	15,400	3,072	20
Depreciation and amortization	29,406	24,173	5,233	22
	$ 152,275	$ 124,859	$ 27,416	22%

Not included in the above for 2005 are unusual items of $3.1 million for accelerated long-term incentive plan compensation expense, $2.0 million for Line 63 oil release costs and $1.8 million for transaction costs. See "Significant Developments in 2005" above for a discussion of these items.

The increase in operating expense was related primarily to our acquisitions of the Rangeland system in May 2004 and the Valero Assets on September 30, 2005. Operating expenses also increased because of $3.0 million of repairs and maintenance associated with earth movement and stream erosion problems caused by record rainfall in Southern California and Alberta. Repairs of two Pacific Terminals storage tanks also adversely affected operating expense in 2005.

The increase in general and administrative expense is associated with the integration and operation of the Rangeland system and Valero Assets and increased personnel costs to support our continued growth. In addition, we incurred more costs for acquisition evaluations in 2005. These increases were partly offset by reduced costs for the Long Term Incentive Plan in 2005.

The increase in depreciation and amortization includes $2.7 million for depreciation and amortization on the Rangeland system and $3.0 million on the assets acquired from Valero, L.P. These increases were partly offset by lower depreciation on assets that have now been fully depreciated.

	Year ended December 31,			
Other Income and Expense	**2005**	**2004**	**Change**	**Percent**
	(In thousands)			
Share of net income of Frontier	$ 1,757	$ 1,328	$ 429	32%
Write-down of idle property	450	800	(350)	(44)
Interest expense	26,720	19,209	7,511	39
Interest and other income	1,119	1,032	87	8
Write-off of deferred financing cost and interest rate swap termination expense		2,901	2,901	

	Year ended December 31,				
Income tax expense	1,163	261	902	346	78

The increase in our share of Frontier's net income was mainly attributable to lower operating costs at Frontier compared to 2004. In 2004, Frontier incurred higher costs for major maintenance and the costs of using a flow improvement agent used to increase pipeline throughput.

In 2005 and 2004 we incurred non-cash impairment expense of $0.5 million and $0.8 million, respectively, associated with idle Pacific Terminals properties. These idle properties were included in the purchase of the Pacific Terminals storage and distribution system in 2003.

The increase in interest expense was due to borrowings incurred to partially fund the Valero Acquisition and due to higher floating interest rates. Our weighted average borrowings during the year ended December 31, 2005 were $407.4 million, compared to $315.3 million in 2004. In addition, floating interest rates were higher in 2005, which resulted in a weighted average interest rate of 6.6% for 2005 compared to a weighted average interest rate of 6.2% in 2004.

Other income in 2005 remained comparable to other income in 2004.

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.

Income tax expense is a function of the income of our Canadian subsidiaries, which are taxable entities. In addition, certain kinds of repatriation of funds into the U.S. subject the Partnership to Canadian withholding tax. Our Canadian subsidiaries income was higher in 2005 compared to 2004 reflecting a full year 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.

Following is a reconciliation of net income to the results of our operations, excluding unusual items mentioned above:

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

The increase in net income, adjusted for unusual items, 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 margins. There were 28.5 million weighted average limited partner units outstanding in the year ended December 31, 2004, approximately 26% more limited partner units than the 22.5 million weighted average units outstanding in the year ended December 31, 2003 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

West Coast	Year ended December 31, 2004	Year ended December 31, 2003	Change	Percent
	(In thousands)			
Operating income	$ 48,739	$ 42,664	$ 6,075	14%
Write-down of idle property	800		800	
	$ 49,539	$ 42,664	$ 6,875	16%
Operating data:				
Pipeline throughput (bpd)	141.2	151.0	(9.8)	(6)%

For the year ended December 31, 2004, West Coast operating income was $48.7 million, after the $0.8 million impairment expense, compared to $42.7 million for 2003. This increase was primarily attributable to a full year benefit of the Pacific Terminals storage and distribution system, which was acquired in July 2003. PMT experienced lower gathering and blending margins in the third and fourth quarters of 2004, as well as reduced demand in its gathering activities. We consider this gathering activity to be generally complementary to our pipeline transportation operations. West Coast pipeline volumes for the year ended December 31, 2004 were 6% lower than in 2003, primarily due to Outer Continental Shelf 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	Year ended December 31, 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, Rocky Mountain operating income was $23.7 million compared to $13.1 million for 2003, largely due to acquisition of the Rangeland system 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. A 7,000 bpd expansion completed in the second quarter of 2004 further increased volumes into Salt Lake City.

Statement of Income Discussion and Analysis

Revenues	2004	2003	Change	Percent
	Year ended December 31,			
	(In thousands)			
Pipeline transportation revenue	$ 108,395	$ 101,811	$ 6,584	6%
Storage and terminaling 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 in 2004 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 that 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 terminaling revenue in 2004 reflects a full year of operations of the Pacific Terminals storage and distribution system, which was acquired in July 2003. In addition, the system's capacity was expanded, utilization rates increased and storage rates per barrel were also higher.

Pipeline buy/sell transportation revenue of $18.6 million in 2004 results from the operations of the Rangeland system, which was acquired in May 2004.

The decrease in net crude oil sales for 2004 was primarily the result of lower margin gathering activities in our West Coast operations, particularly due to lower gathering 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 activity to be generally complementary to our pipeline transportation operations.

Expenses	2004	2003	Change	Percent
	Year ended December 31,			
	(In thousands)			
Operating expenses	$ 85,286	$ 61,046	$ 24,240	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 in 2004 was related primarily to the acquisition of the Pacific Terminals storage and distribution assets in July 2003 and the Rangeland system in May 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.

The increase in general and administrative expense in 2004 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 in 2004 includes $2.0 million for depreciation and amortization 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
Interest and 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 in 2004 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, Frontier incurred expenses 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, a sale which closed in 2005.

The increase in interest expense in 2004 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 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 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 in 2004 related 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.

Income tax expense for 2004 relates to 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.

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 intend to finance our future acquisitions and development projects, including our Pier 400 project, with issuances of debt and equity securities. We expect to maintain a debt to total capitalization ratio of approximately 50% over time.

On December 23, 2005, we and certain of our subsidiaries 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 our needs, of up to $1.0 billion of common units of the Partnership and debt securities of both the Partnership and certain subsidiaries. This shelf registration statement will allow us to finance new acquisitions and new projects such as our Pier 400 Project. In addition, we have $110 million available and remaining under our August 2003 universal shelf registration statement.

We received permission from the CPUC to dismantle certain idle PT assets and sell the underlying land, which has an estimated value of approximately $10 million at December 31, 2005. In addition, in the fourth quarter of 2005, we sold one parcel of idle PT land for net proceeds of $1.6 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 and refined products transported through our pipelines and the volume leased in our storage tanks as described in "Overview" above. Our operating performance is also affected by prevailing economic conditions in the crude oil and refined products industries 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,		
	2005	2004	2003
		(In thousands)	
Net cash provided by operating activities	$ 76,108	$ 57,226	$ 42,723
Net cash used in investing activities	(512,751)	(155,952)	(180,332)
Net cash provided by financing activities	431,280	112,410	123,435

Net cash provided by operating activities

Net cash from operating activities for the year ended December 31, 2005 was higher than in 2004, because of a full year's operation of our Rangeland system and due to the Valero Acquisition that closed on September 30, 2005. In addition, we had higher cash from operating income on our U.S. Rocky Mountain pipelines. These increases in cash were partially offset by lower operating income on our West Coast pipelines because of natural field decline, $2.0 million for costs associated with an oil release on Line 63, and additional repair and maintenance costs associated with earth movement and stream erosion problems caused by the record rainfall in Southern California and Alberta, Canada. Net cash provided by operating activities in 2005 was also increased by approximately $2.0 million in working capital changes.

Net cash provided by operations was higher in 2004 than in 2003, primarily because of a full year's operation of our Pacific Terminals storage and distribution system and the purchase of the Rangeland system in 2004, 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 margins. Net cash provided by operating activities in 2004 was reduced by approximately $8.0 million used for working capital purposes.

Net cash used in investing activities

On September 30, 2005, we purchased the Valero Assets for an aggregate purchase of $455.0 million plus transaction costs of approximately $3.7 million. Separately, we also purchased certain crude oil contracts and crude oil inventories for $3.8 million plus contingent payments to be measured over the period July 1, 2005 through December 31, 2008 based on specified performance criteria. Capital expenditures were $51.7 million for the year ended December 31, 2005, of which $6.1 million related to sustaining capital projects, $11.4 million related to transition projects, $26.4 million related to expansion, and $7.8 million was invested towards our continued development of the Pier 400 Project.

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 $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 integration of RMPS and the Pacific Terminals storage and distribution system, and $8.4 million related to expansion, including the Pier 400 expenditures noted above.

Net cash provided by financing activities

Cash provided by financing activities for the year ended December 31, 2005 includes net proceeds of $295.1 million, including our General Partner's capital contribution of $6.1 million from our public and private equity offerings, $170.9 million net proceeds from the offering of our $6^1/_4$% senior notes, and net proceeds of $140.6 million under our new revolving credit facility. In September 2005, we repaid in full the outstanding balance of $171.0 million under our previous U.S. and Canadian revolving credit facilities. During 2005, we incurred net borrowings of $64.3 million under our previous U.S. and Canadian revolving credit facilities. Cash provided by financing activities for 2005 also reflect cash distributions to partners of $66.8 million and a $2.4 million contribution from The Anschutz Corporation and LBP to reimburse us for certain costs incurred in connection with the LB Acquisition.

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 $7^1/_8$% 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 previous U.S. and Canadian revolving credit facilities. We incurred $1.2 million of costs to establish our previous Canadian revolving credit facility. 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 previous U.S. revolving credit facility. Borrowings under our previous Canadian revolving credit facility were also used to fund the Rangeland system and the MAPL pipeline acquisitions. Finally in 2004, we paid cash distributions of $56.5 million to our partners.

The 2003 balance of $123.4 million includes net proceeds of $73.0 million under our previous U.S. 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. Cash provided from financing activities in 2003 is net of $42.1 million in cash distributions paid to our partners.

Capital Requirements

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

- sustaining capital expenditures to replace assets in order to maintain the original operating capacity or efficiency of our assets or extend their useful lives;

- transitional capital expenditures to integrate newly-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 adding new pump stations or pipeline connections to increase our throughput capacity.

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

	Year Ended December 31,		
Capital Expenditures	**2005**	**2004**	**2003**
		(in thousands)	
Sustaining capital expenditures	$ 6,067	$ 1,953	$ 2,149
Transitional capital expenditures	11,401	1,874	351
Expansion capital expenditures	34,249	12,693	8,392
Total	$ 51,717	$ 16,520	$ 10,892

We expect to invest approximately $120 million in total capital expenditures in 2006, with approximately $106 million of that total on expansion projects. Our estimated 2006 expansion capital spending includes the following notable projects.

2006 Budgeted Expansion Capital Expenditures	**Estimated to be incurred in 2006**
	(in millions)
First phase of Salt Lake City expansion	$ 32
Capital projects associated with the Valero Assets	23
Completion of permitting process, engineering and other project development cost for the Pier 400 project	21
Reactivation of storage tanks and expansion of infrastructure at PT	11
Completion of storage tanks for the Rangeland System and Western Corridor pipeline to facilitate the transportation of synthetic crude oil	4
Other	15
Total	$ 106

In addition to the expansion projects above, we expect to incur $6 million for transitional capital expenditures and $8 million for sustaining capital expenditures.

Pier 400

We continue our efforts to develop 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. As currently envisioned, the project would include a deep water berth, high capacity transfer infrastructure and storage tanks, with a pipeline distribution system that will connect to various customers, some directly, and some through our Pacific Terminals storage and distribution system. We would construct the storage tanks and transfer infrastructure, including a large diameter pipeline system for receiving bulk petroleum liquids from marine vessels. If successful, this project will allow us to increase our participation in the Los Angeles basin marine import business, which is growing as a result of a decline in both California production and imports from Alaska.

We have entered into agreements with ConocoPhillips and two subsidiaries of Valero Energy Corporation that provide long term customer commitments to off-load a total of 140,000 bpd of crude oil at the Pier 400 dock. The Valero and ConocoPhillips agreements are subject to satisfaction of various conditions, such as the achievement of various progress milestones, financing, continued economic viability, and completion of other ancillary agreements related to the project. We are negotiating similar long term off-loading agreements with other potential customers.

We recently completed an updated cost estimate for the project. We are estimating that Pier 400 will cost approximately $250 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 3.0 million barrels of storage, although we are seeking permits for and will likely build 4.0 million barrels of storage. We are 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, the Los Angeles City Council and the U.S. Army Corps of Engineers. We expect to have the necessary permits in the second half of 2006.

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 approvals, securing additional customer commitments, updating engineering and project cost estimates, ongoing feasibility evaluation, and financing. We expect construction of the Pier 400 terminal to be completed and the facility to be placed in service in late 2007 or early 2008.

We have capitalized $18.3 million on the Pier 400 project through December 31, 2005, including $7.8 million during 2005. These expenditures include $8.2 million for emission reduction credits, an asset that is re-saleable if the project does not proceed. We anticipate funding the remaining permitting and pre-construction costs in 2006 from our revolving credit facility. 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.

Credit Facilities and Long-Term Debt Incurred in 2005

$400 million Senior Secured Credit Facility

On September 30, 2005, we entered into a new five-year $400 million senior secured revolving credit facility (the "New Credit Facility") that replaced our previous U.S. and Canadian revolving credit facilities. The New Credit Facility is available for general Partnership purposes in the U.S. and Canada, including working capital, letters of credit and distributions to unitholders (subject to certain limitations). The New Credit Facility matures on September 30, 2010, but we may prepay all borrowings under the New Credit Facility without premium or penalty. Obligations under the New Credit Facility are guaranteed by all of our subsidiaries except those for which regulatory approval is required and are secured by substantially all of the assets of the Partnership, excluding property held by the non-guaranteeing subsidiaries. The New Credit Facility is recourse to us and the guarantors, but non-recourse to the General Partner.

Subject to certain limited exceptions, indebtedness under the New 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

Bank of America, N.A. or the Federal Funds rate plus 0.50% (or in the case of borrowings under the Canadian sub-facility described below, Canadian US dollar base rate or Canadian prime rate) each plus an applicable margin ranging from 0% to 0.75% or (ii) the Eurodollar rate plus an applicable margin ranging from 0.75% to 2.0%. The applicable margins fluctuate based on our credit rating at any given time. In addition, we will incur a commitment fee which ranges from 0.1875% to 0.50% per annum on the unused portion of the New Credit Facility.

Included in the New Credit Facility is a Canadian sub-facility for Rangeland Pipeline Company ("RPC"), one of our Canadian subsidiaries. The Canadian sub-facility currently has a limit of U.S.$100 million, but can be adjusted from time to time by us. The Canadian sub-facility includes an option for RPC to receive loans in either U.S. dollars or Canadian dollars.

The New Credit Facility contains certain financial covenants and covenants limiting our ability to, among other things, incur or guarantee indebtedness, change ownership or structure, including mergers, consolidations, liquidations and dissolutions, sell or transfer assets and properties, and enter into a new line of business. At December 31, 2005, the Partnership was in compliance with all such covenants.

As of December 31, 2005, $140.8 million was outstanding under the New Credit Facility, including $55.8 million under the Canadian sub-facility, and there was $125.5 million of undrawn available credit.

The New Credit Facility was entered into with a syndicate of financial institutions, including an affiliate of Lehman Brothers, Inc., which is an affiliate of LBP (see "Item 13 Certain Relationships and Related Transactions").

6$^{1}/_{4}$% Senior Notes Due 2015

On September 23, 2005, we and our 100% owned subsidiary, Pacific Energy Finance Corporation, completed the sale of $175.0 million of 6$^{1}/_{4}$% senior unsecured notes due September 15, 2015. The 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 Registration S of the Securities Act. In January 2006, the 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 notes were sold for 99.544% of face value resulting in an effective interest rate of 6.3125% to maturity. Interest payments are due on March 15 and September 15 of each year, beginning on March 15, 2006. Net proceeds from the issuance of the notes were $170.9 million after deducting the $0.8 million discount and offering expenses of $3.3 million. The net proceeds were used to partially fund the Valero Acquisition.

The notes are jointly and severally guaranteed by certain of our subsidiaries, namely Pacific Energy Group LLC, Pacific Marketing and Transportation LLC, Pacific Atlantic Terminals LLC, Rocky Mountain Pipeline System LLC, Ranch Pipeline LLC, PEG Canada GP LLC and PEG Canada, L.P.

At any time prior to September 15, 2008, we have the option to redeem up to 35% of the aggregate principal amount of notes at a redemption price of 106.25% of the principal amount with the net cash proceeds of one or more equity offerings. At any time prior to September 15, 2010, we may redeem some or all of the notes at a price equal to 100% of the principal amount, plus a make-whole premium and accrued and unpaid interest, if any, to the date of redemption. We will also have the option to redeem the notes, in whole or in part, at any time on or after September 15, 2010 at the following redemption prices:.

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

The indenture governing the notes contains certain covenants that, among other things, limit our ability and the ability of our 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; or consolidate, merge or transfer all or substantially all of their assets. At December 31, 2005, we were in compliance with all such covenants.

Contractual Obligations

In our ongoing operations, we are bound by certain contractual obligations. Following is a summary of our monetary contractual obligations as of December 31, 2005.

	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	$ 565,632	$	$ 3,979	$ 140,751	$ 420,902
Interest payments on fixed-rate long-term debt	256,961	28,750	57,500	57,500	113,211
Right-of-way obligations(1)	90,151	4,041	9,007	9,811	67,292
Operating lease obligations	3,784	1,378	1,802	576	28
Total	$ 916,528	$ 34,169	$ 72,288	$ 208,638	$ 601,433

(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 years" and "more than 5 years" 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, $3.4 million and $2.9 million in 2005, 2004 and 2003, respectively.

Off-Balance Sheet Arrangements

We provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. These letters of credit are issued under our credit facility, and the liabilities with respect to these purchase obligations are recorded in "Accrued crude oil purchases" on our balance sheet in the month the crude oil is purchased. Generally, these letters of credit are issued for up to sixty-day periods and are terminated upon completion of each transaction. In addition, we have provided a letter of credit to the seller of the MAPL pipeline to secure a Cdn$5.0 million note payable in June 2007. At December 31, 2005, we had outstanding letters of credit totaling approximately $14.8 million. For a description of certain operating leases please see "Note 14 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, 2005, 2004 or 2003.

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 are now, and may from time to time in the future, be subject to environmental cleanup and enforcement actions.

The accompanying Partnership 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. There were no stock options or restricted stock units outstanding as of December 31, 2005. We will adopt SFAS 123R on January 1, 2006 and apply its provisions to future grants.

In December 2004, the FASB issued Statement of Financial Accounting Standards No. 153, *Exchanges of Nonmonetary Assets* ("SFAS 153"). SFAS 153 addresses the measurement of exchanges of certain nonmonetary assets (except for certain exchanges of products or property held for sale in the ordinary course of business). It amends APB Opinion No. 29, *Accounting for Nonmonetary Exchanges*, and requires that nonmonetary exchanges be accounted for at the fair value of the assets exchanged, with gains or losses being recognized, if the fair value is determinable within reasonable limits and the transaction has commercial substance, as defined in SFAS 153. We adopted SFAS 153 on July 1, 2005, and the adoption did not have a material impact on the consolidated financial statements.

On March 30, 2005 the FASB issued FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations*("FIN 47"), to clarify the term *conditional asset retirement obligation* as that term is used in FASB Statement No. 143, *Accounting for Asset Retirement Obligations*. The Interpretation also clarifies when an entity has sufficient information to reasonably estimate the fair value of an asset retirement obligation. FIN 47 was effective for us as of December 31, 2005. The adoption of FIN 47 did not have a material impact on our financial statements.

In May 2005, the FASB issued Statement of Financial Accounting Standards No. 154, *Accounting Changes and Error Corrections* ("SFAS 154"). SFAS 154 replaces APB No. 20, *Accounting Changes,* and FASB Statement No. 3, *Reporting Changes in Interim Financial Statements.* The Statement changes the accounting for, and reporting of, a change in accounting principle. SFAS 154 requires retrospective application to prior period's financial statements of voluntary changes in accounting principle and changes required by new accounting standards when the standard does not include specific transition provisions, unless it is impracticable to do so. SFAS 154 is effective for accounting changes and corrections of errors in fiscal years beginning after December 15, 2005. If required, we will apply the provisions of SFAS 154 in future periods.

In September 2005, the Emerging Issues Task Force ("EITF") issued Issue No. 04-13 ("EITF 04-13"), *Accounting for Purchases and Sales of Inventory with the Same Counterparty*. The issues addressed by the EITF are (i) the circumstances under which two or more exchange transactions involving inventory with the same counterparty should be viewed as a single exchange transaction for the purposes of evaluating the effect of APB No. 29; and (ii) whether there are circumstances under which nonmonetary exchanges of inventory within the same line of business should be recognized at fair value. EITF 04-13 is effective for new arrangements entered into in the reporting periods beginning after March 15, 2006, and to all inventory transactions that are completed after December 15, 2006, for arrangements entered into prior to March 15, 2006. We are in the process of determining the impact of EITF 04-13 on our financial statements, but do not expect it to have a material impact on our 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 commodity price risk, interest rate risk and currency exchange risk. We use derivative financial instruments to reduce our exposure to adverse fluctuations in commodity prices, interest rates and foreign exchange rates. We formally designate and document the financial instruments as a hedge of a specific underlying exposure, as well as the risk management objectives and strategies for undertaking the hedge transactions. We formally assesses, both at the inception and at least quarterly thereafter, whether the financial instruments that are used in hedging transactions are effective at offsetting changes in either the fair value or cash flows of the related underlying exposure. All of our derivatives are commonly used over-the-counter instruments with liquid markets or are traded on the New York Mercantile Exchange. We do not enter into derivative financial instruments for trading or speculative purposes.

Commodity Price Risk Hedging

We may use derivatives, principally futures and options, to hedge our exposure to market price volatility related to our inventory or future sales of crude oil. Derivatives used to hedge market price volatility related to inventory are generally designated as fair value hedges, and derivatives related to future sale of crude oil are generally classified as cash flow hedges. Derivative instruments are included in "Other assets" in the accompanying consolidated balance sheets.

Changes in the fair value of our derivative instruments related to crude oil inventory are recognized in net income. For the years ended December 31, 2005, 2004 and 2003, "crude oil sales, net of purchases" were net of $0.8 million, $2.7 million and $0.3 million in losses, respectively, reflecting changes in the fair value of derivative instruments held as hedges related to crude oil marketing activities. Losses on derivatives were generally offset by gains in physical crude oil inventory positions. Changes in the fair value of our derivative instruments related to the future sale of crude oil are deferred and reflected in "accumulated other comprehensive income," a component of partners' capital in the balance sheet, until the related revenue is reflected in the consolidated statements of income. As of December 31, 2005, a $0.1 million loss relating to the change in the fair value of highly effective derivative instruments was included in "accumulated other comprehensive income" and is expected to be reclassified to earnings in 2006. Since these amounts are based on market prices at December 31, 2005, actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

Interest Rate Risk Hedging

In connection with the issuance of our 7$^1/_8$% senior notes due 2014, 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$% and to pay interest at an average variable rate of six month LIBOR plus 1.6681% (set in advance or in arrears depending on the swap transaction). The interest rate swaps mature June 15, 2014 and are callable at the same dates and terms as the 7$^1/_8$% 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, 2005 the Partnership recorded an increase of $0.6 million in the fair value of interest rate swaps with an equal offsetting entry to the $80.0 million of senior notes. During the year ended December 31, 2005, we recognized reductions in interest expense of $1.3 million related to the difference between the fixed rate and the floating rate of interest on the interest rate swaps. As of December 31, 2005, we had an immaterial amount of ineffectiveness relating to these interest rate swaps.

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 our interest rates were to increase 1.0% in 2006 as compared to the rate at December 31, 2005, our interest expense for 2006 would increase $2.2 million based on our outstanding debt balances at December 31, 2005.

Currency Exchange Rate Risk Hedging

The purpose of our foreign currency hedging activities is to reduce the risk that our cash inflows resulting from interest payments from our Canadian subsidiaries on intercompany debt will be adversely affected by changes in the U.S./Canadian exchange rate.

We entered into forward exchange contracts to hedge receipt of forecasted interest payments denominated in Canadian dollars. The effective portion of the change in fair value of this contract, which has been designated as a cash flow hedge, is reported in "accumulated other comprehensive income" in the accompanying balance sheet and will be reclassified into earnings in "Other income" in the same period during which the hedged transaction affects earnings. The ineffective portion, if any, of the change in fair value of this instrument will be immediately recognized in earnings. These foreign exchange contracts are as follows:

	Canadian dollars	US dollars	Average Exchange Rate
	(in thousands)		
2006	$ 7,200	$ 6,126	Cdn$1.18 to U.S. $1.00
2007	6,600	5,662	Cdn$1.17 to U.S. $1.00
2008	3,193	2,754	Cdn$1.16 to U.S. $1.00

Credit Risks

By using derivative financial instruments to hedge exposures related to changes in commodity prices, interest rates and currency exchange rates, we expose ourselves to market risk and credit risk. Market risk is the risk of loss arising from the adverse effect on the value of a financial instrument that results from changes in commodity prices, interest rates or currency exchange rates. The market risk associated with price volatility is managed by established parameters that limit the types and degree of market risk that may be undertaken.

Credit risk is the risk of loss arising from the failure of the derivative agreement counterparty to perform under the terms of the derivative agreement. When the fair value of a derivative agreement is positive, the counterparty is liable to us, which creates credit risk for us. When the fair value of a derivative agreement is negative, we are liable to the counterparty and, therefore, it creates credit risk for the counterparty. The counterparties we transact with are large, well known companies in the industry or large creditworthy financial institutions. As such, we believe our exposure to counterparty credit risk is low. Nonetheless, there can be no assurance as to the performance of a counterparty.

Fair Value of Financial Instruments

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

	December 31,			
	2005		2004	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Crude oil hedging futures	$ 161	$ 161	$ 400	$ 400
Fair value interest rate swaps	567	567	2,693	2,693
Foreign exchange contracts	195	195		
Long-term debt	565,632	576,015	357,163	373,265

The carrying amount of derivative financial instruments represents 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 and foreign exchange contracts 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 this 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 Disclosures

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. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management is required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

Based on their evaluation as of December 31, 2005, 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, 2005. Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005 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, 2005 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, 2005, 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, 2005, 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, 2005, 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, 2005 and 2004, 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, 2005, and our report dated March 10, 2006, expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Los Angeles, California
March 10, 2006

ITEM 9B. Other Information

None.

Part III

ITEM 10. Directors and Executive Officers of the Registrant

We are managed by our general partner, Pacific Energy GP, LP, a Delaware limited partnership, which is managed by 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 Pacific Energy GP, LP and the Partnership.

The following table shows information for the directors and executive officers of PEM as of February 28, 2006.

Name	Age	Position with the General Partner
Christopher R. Manning	38	Chairman of the Board of Directors
Forrest E. Wylie	42	Vice Chairman of the Board of Directors
Joshua L. Collins	41	Director
Timothy H. Day	35	Director
David L. Lemmon	63	Director
John C. Linehan	66	Director
Douglas L. Polson	64	Director
Jim E. Shamas	71	Director
William L. Thacker	60	Director
Irvin Toole, Jr.	64	President, Chief Executive Officer and Director
David E. Wright	60	Executive Vice President, Corporate Development
Gerald A. Tywoniuk	44	Senior Vice President, Chief Financial Officer
Lynn T. Wood	54	Vice President, General Counsel and Secretary
Arthur G. Diefenbach	55	Senior Vice President, West Coast Business Unit
Gary L. Zollinger	57	Senior Vice President, Rocky Mountain Business Unit
Lyle B. Boarts	63	Vice President, Human Resources
Marilyn A. Lobel	52	Vice President, Corporate Controller and Chief Accounting Officer

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. Mr. Manning is a member of the Nominating and Governance and Compensation Committees of the Partnership. Mr. Manning is currently a director of Antero Resources Corporation and RSI Holding Corporation and holds an observer seat on the board of directors of Enduring Resources LLC.

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 Managing Director of Lehman Brothers. Mr. Collins Joined LBMB in 1996.

Mr. Collins is currently a director of Blount International Inc., EverGreen Copyright Acquisitions, LLC, Enduring Resources LLC and Phoenix Brands LLC.

Timothy H. Day was elected to the Board of Directors in April 2005. Mr. Day was elected to the board of directors pursuant to the Second Amended and Restated Limited Liability Company Agreement of LB Pacific GP, LLC, and the Second Amended and Restated Limited Partnership Agreement of LB Pacific, both of which were entered into pursuant to the Purchase Agreement by and among First Reserve Pacific Holdings AIV, L.P., Lehman Sidecar I, LLC and LB I Group Inc. dated March 21, 2005. These agreements provide that so long as First Reserve Pacific Holdings AIV, L.P. holds a certain number of shares in LB Pacific GP, LLC or a certain number of units in LB Pacific, then First Reserve Pacific Holdings AIV, L.P. has the right to cause LB Pacific GP, LLC to cause LB Pacific to elect a designee to serve on the board of directors of PEM. Mr. Day is a director and vice president of First Reserve Corporation and serves on the board of directors of Chart Industries, Inc. Mr. Day joined First Reserve Corporation in 2002. Prior to joining First Reserve Corporation, Mr. Day held various positions with SCF Partners, a Houston, Texas based investment firm, from 1995 to 2000. Previously, Mr. Day served in the energy investment banking divisions of Credit Suisse First Boston and Salomon Brothers Inc.

David L. Lemmon was elected to the Board of Directors in April 2002. Mr. Lemmon served as President and Chief Executive Officer of Colonial Pipeline Company from November 1997 to January 2006 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 the 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 the 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 the 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 October 2002, Mr. Thacker held various positions at Texas Eastern Products Pipeline Co., LLC, which was, at the time, 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. and Mirant Corp.

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 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. Previously, 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.

Marilyn A. Lobel was appointed as Vice President, Corporate Controller and Chief Accounting Officer in February 2006. Previously, Ms. Lobel served as Vice President, Corporate Controller at Biolase Technology, Inc. from June 2004 through December 2005. From January 2004 through June 2004, she served as finance consultant to various publicly traded firms. From May 2002 through December 2003, she served as Director of Finance at Xoma Ltd. Prior to joining Xoma Ltd., she served as Vice President of Finance and Interim Chief Financial Officer from August 2001 through May 2002 and Vice President of Finance and Corporate Controller from January 1999 through July 2001 for Tut Systems, Inc.

The following table shows other officers of PEM as of February 28, 2006:

Name	Age	Position with the General Partner
Stephen F. Blackwood	43	Vice President, Treasurer
Dominic D. Ferrari	52	Vice President, Corporate Development
John Kers	57	Vice President, Operations and Technical Services Canada
Jesse G. Metcalf	55	Vice President, Operations and Technical Services Rocky Mountains
Khalid A. Muslih	34	Vice President, Corporate Development
Edward L. Scheibelhut	46	Vice President, Marketing and Business Development Canada
John Tsouvalas	47	Vice President, Marketing and Business Development West Coast

Stephen F. Blackwood was elected Vice President and Treasurer in September 2005. Mr. Blackwood previously served as Director of Global Treasury at Amgen Inc. and held various management positions in the Treasury group at Amgen since 1998. Prior to Amgen, Mr. Blackwood served as Vice President Treasury at Deposit Guaranty Corp and held various positions in the treasury group since 1992.

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 previously served as 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.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires directors, officers and persons who beneficially own more than 10% 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, our General Partner in its capacity as a beneficial owner and any other persons who beneficially own more than 10% of our common units complied with all filing requirements with respect to transactions in our equity securities in 2005, except that Mr. Polson inadvertently omitted from reports filed by him on Form 4 during 2005 four sales transactions pursuant to a 10b5-1 plan, involving 100, 200, 500 and 500 of our common units, which were omitted as a result of administrative error by Mr. Polson's brokerage firm.

Director Independence

The New York Stock Exchange ("NYSE") listing standards requiring a majority of directors to be independent do not apply to publicly traded limited partnerships like the Partnership. Four directors are "independent" as that term is defined in the applicable NYSE rules and Rule 10A-3 of the Exchange Act. In determining the independence of each director, the Board has adopted certain categorical standards. PEM's independent directors as determined in accordance with those standards are: David L. Lemmon, Jim E. Shamas, John C. Linehan and William L. Thacker. The categorical standard adopted by the Board are as follows:

- A director will not be considered independent if the director is, or has been within the last three years, an employee of the Partnership or the General Partner or any of its subsidiaries, PEM, or LB Pacific or its general partner (collectively, the "Partnership Group"), or if an immediate family member of a director is, or has been within the last three years, an executive officer of any member of the Partnership Group; provided however, that employment as an interim Chairman or Chief Executive Officer or other executive officer will not disqualify a director from being considered independent following that employment;

A director who has received, or has an immediate family member who has received, during any twelve-month period within the last three years, more than $100,000 in direct compensation from the Partnership Group, other than director and committee fees and pension or other forms of deferred compensation for prior services (provided such compensation is not contingent in any way on continued service), will not be considered independent; provided, however, that the following need not be considered in determining independence under this test: (i) compensation received by a director for former service as an interim Chairman or Chief Executive Officer or other executive officer and (ii) compensation received by an immediate family member for service as an employee (other than an executive officer) of any member of the Partnership Group;

A director will not be considered independent if (i) the director or an immediate family member is a current partner of a firm that is the Partnership's internal or external auditor; (ii) the director is a current employee of such a firm, (iii) the director has an immediate family member who is a current employee of such a firm and who participates in the firm's audit, assurance or tax compliance (but not tax planning) practice; or (iv) the director or an immediate family member was within the last three years (but is no longer) a partner or employee of such a firm and personally worked on the Partnership's audit within that time;

A director or immediate family member who is, or has been within the last three years, employed as an executive officer of another company where any of the present executive officers of any member of the Partnership Group at the same time serves or served on that company's compensation committee will not be considered independent; and

A director who is a current employee, or whose immediate family member who is a current executive officer, of a company that has made payments to, or received payments from, one or more members of the Partnership Group for property or services in an amount which, in any of the last three fiscal years, exceeds the greater of $1 million, or 2% of such other company's consolidated gross revenues, will not be considered independent; provided, however, that charitable organizations will not be considered to be a company for purposes of this test.

For purposes of the above-described categorical standards, the term "immediate family member" includes a person's spouse, parents, children, siblings, mothers- and fathers-in-law, sons- and daughters-in-law, brothers- and sisters-in-law and anyone (other than domestic employees) who shares such person's home; provided, that any such persons who no longer have any such relationship as a result of legal separation or divorce, or death or incapacitation, shall not be considered immediate family members.

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 six special meetings during 2005. 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 six meetings during 2005.

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 five meetings during 2005.

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 a determination from the Conflicts Committee as to whether a potential transaction involving 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 four meetings during 2005.

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 2005.

Executive Sessions

The Board of Directors holds executive sessions for the non-management directors on a regular basis without management present. Since the non-management directors include directors who are not independent directors, the independent directors also 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 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 PEM's corporate secretary. Letters addressed to the Board of Directors in general will be reviewed by PEM's 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 are to be forwarded by the recipient director to the chair of the Audit Committee.

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, and is available in print to any holder of our units who requests it from our Investor Relations Department. 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.

Corporate Governance Matters

The NYSE requires the chief executive officer of each listed company to certify annually that he is not aware of any violation by the company of the NYSE corporate governance listing standards as of the date of the certification, qualifying the certification to the extent necessary. The Chief Executive Officer of the General Partner provided such certification to the NYSE in 2005 without qualification. In addition, the certifications of the General Partner's Chief Executive Officer and Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act have been included as exhibits to the Partnership's Annual Report on Form 10-K.

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.

ITEM 11. Executive Compensation

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(3)**	**Unit Option Grants**	**LTIP Payouts(4)**	**All Other Compensation(5)**
Irvin Toole, Jr. President, Chief Executive Officer and Director	2005	$ 291,250	$ 244,694	$	$	$ 806,250	$ 14,846
	2004	273,333	184,470			696,000	12,300
	2003	260,000	104,657			678,500	12,050
Forrest E. Wylie(1) Vice Chairman of the Board of Directors	2005	206,440	183,659				11,250
David E. Wright Executive Vice President, Corporate Development	2005	221,750	105,340			725,625	13,305
	2004	214,000	123,567			208,800	12,300
	2003	206,500	57,903			203,625	5,679
Gerald A. Tywoniuk Senior Vice President and Chief Financial Officer	2005	212,375	74,391			354,750	12,742
	2004	205,625	79,924			55,680	12,300
	2003	200,000	44,725	88,171		54,300	9,000
Lynn T. Wood Vice President, General Counsel and Secretary	2005	180,125	52,461			483,750	21,615
	2004	174,500	67,390			139,200	14,385
	2003	170,000	35,721	167,322		135,750	8,075
Douglas L. Polson(2) Director and former Chairman of the Board of Directors	2005	84,673		75,000			906,000
	2004	293,333	199,287			2,087,250	24,600
	2003	280,000	112,042			1,962,000	24,033

(1) Mr. Wylie became an employee of our General Partner on March 4, 2005. Mr. Wylie's current annual salary is $250,000.

(2) Mr. Polson resigned as Chairman of the Board of Directors in March 2005 but remains a director. His director fees earned subsequent to such date are excluded from this table. |

(3) Represents consulting fees of $75,000 for Mr. Polson. Includes, for Mr. Tywoniuk and Mr. Wood, reimbursement of relocation expenses, including reimbursement of associated income taxes of $33,027 and $64,612, respectively. |

(4)

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. |

(5)

Includes for Mr. Polson $900,000 paid pursuant to his employment agreement (see "Employment Agreements Douglas L. Polson" below) and a Special Agreement. LBP reimbursed us as described in "Employment Agreements Douglas L. Polson" below. All other amounts reflect employer contribution to our General Partner's 401(k) plan.

Option Exercises

During 2005, Mr. Polson exercised 50,000 common unit options, which had vested in 2003 and 2004, for an aggregate dollar value of $667,500 (closing market price on the day prior to exercise less exercise price). No other individuals named in the Summary Compensation Table above hold common unit options.

Long-Term Incentive Plan Awards

2005 Grants

No common unit options were granted in 2005, and none are currently outstanding. No restricted units were granted in 2005 to the individuals named in the Summary Compensation Table above.

2006 Grants

In January 2006, our General Partner awarded restricted units to key employees that vest over a three year period, beginning on March 1, 2006, and that are also subject to meeting annual financial performance objectives. The financial measure used is the Partnership's distributable cash flow per unit, as determined by the Committee, for the calendar year preceding each of the three annual vesting dates. The number of units to be delivered in any year, if any, will be a portion of the number vested on March 1 of that year based on accomplishment of performance targets for the previous calendar year.

			Estimated Future Payouts		
Name	**Number of Restricted Units**	**Performance Period**	**Threshold (# units)**	**Target (# units)**	**Maximum (# units)**
Irvin Toole, Jr.	4,510	3 years	2,255	4,510	6,765
Forrest E. Wylie	3,050	3 years	1,525	3,050	4,575
David E. Wright	2,050	3 years	1,025	2,050	3,075
Gerald A. Tywoniuk	1,630	3 years	815	1,630	2,445
Lynn T. Wood	1,110	3 years	555	1,110	1,665

Depending on our actual results of distributable cash flow per unit for each of the 2005 through 2007 fiscal years, compared to pre-established targets, each participant will receive an amount of units between the threshold and maximum number. If the threshold distributable cash flow target is not met for a particular year, no units will vest. The Compensation Committee has the power to adjust the number of units vested**.**

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. The previous annual compensation was $30,000. Effective February 2006, each non-employee director who serves as audit committee chairman will receive an additional stipend of $7,500 per annum, and each other standing committee chairman will receive an additional stipend of $2,500 per annum. Our General Partner paid no director's fee to directors who were also officers or employees of The Anschutz Corporation, Lehman Brothers Holdings Inc., our General Partner or their affiliates. In 2003, three 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. There were no new grants in 2005. In connection with the closing of the LB Acquisition on March 3, 2005, all of the restricted units outstanding under our long-term incentive plan vested. In January 2006, each outside director received a grant of 3,000 restricted units, which are scheduled to vest over the next three 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. We and certain of our affiliates have agreed to fully indemnify each director for his actions associated with being a director to the fullest extent permitted under Delaware law.

Employment Agreements

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 is reimbursed for reasonable expenses incurred in his capacity as President and Chief Executive Officer and for the cost of owning and operating 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 is reimbursed for reasonable expenses incurred in his capacity as Executive Vice President, Corporate Development and Marketing and for the cost of owning and operating 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 is reimbursed for reasonable expenses incurred in his capacity as Chief Financial Officer and for the cost of owning and operating 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 is reimbursed for reasonable expenses incurred in his capacity as Vice President, General Counsel and Secretary and for the cost of owning and operating 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.

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 of our General Partner effective March 3, 2005. Pursuant to the Special Agreement, Mr. Polson was paid $900,000 in satisfaction of obligations under the Employment Agreement. Pursuant to the Ancillary Agreement, LBP reimbursed us for this amount. Mr. Polson now serves as a non-executive member of the Board of Directors of PEM. Pursuant to the Consulting Agreement, Mr. Polson agreed to perform advisory services to PEM as 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 had a one-year term that expired on March 3, 2006, Mr. Polson received 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.

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. Grant levels, the type of award and the frequency of grants for designated employees will be recommended 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 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. 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**.** 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 or pro-rated vesting, such as the retirement of the grantee when the grantee is eligible for retirement, 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 to date.

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.

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 2005, 2004 and 2003.

Restricted Units	2005(1)	2004	2003
Opening balance, beginning of year	144,750	272,000	368,750
New grants		11,500	34,000
Vesting(2)	(144,750)	(135,750)	(130,750)
Forfeitures		(3,000)	
Ending balance, end of year		144,750	272,000

(1) 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.

(2) Includes units relinquished in satisfaction of withholding taxes.

Unit Options	2005	2004	2003
Opening balance, beginning of year	50,000	50,000	50,000
New grants			
Vesting	(50,000)		
Forfeitures			
Ending balance, end of year		50,000	50,000

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.

LB Pacific, LP Option Plan

LBP, the owner of our General Partner, has adopted an option plan for officers, directors, employees, advisors, and consultants of Pacific Energy Management LLC, LBP, and their affiliates. Under the plan, participants may be granted options to acquire partnership interests in LBP. We are not obligated to pay any amounts to LBP for the benefits granted or paid to our executives and key employees under the Plan, although generally accepted accounting principles require that we record an expense in the Partnership's financial statements with a corresponding increase in the general partner's capital account.

The option plan is administered by the board of directors of LB Pacific GP, LLC. The terms, conditions, performance goals, restrictions, limitations, forfeiture, vesting or exercise schedule, and other provisions of grants under the plan, as well as eligibility to participate are determined by the board of directors of LB Pacific GP, LLC. The board of directors of LB Pacific GP, LLC may determine to grant options under the plan to participants containing such terms as the board of LB Pacific GP, LLC shall determine. 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, options granted will become exercisable over a period determined by the board of directors of LB Pacific GP, LLC. In addition, the board of directors of LB Pacific GP, LLC may determine whether any unit options may become exercisable upon a change in control of LB Pacific GP, LLC, LB Pacific, LP, or our General Partner.

The board of directors of LB Pacific GP, LLC may terminate or amend the unit option 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.

Information concerning the plan and grants is shared by LB Pacific, LP with our Compensation Committee and Board of Directors, and considered in determining the appropriate level of long term compensation paid for by the Partnership.

No option grants were made pursuant to the plan during 2005. In January 2006, the following grants were made to the individuals in the Summary Compensation Table above:

Name	Potential ownership percentage in LB Pacific, LP(1)	Percentage of total options granted to our employees	Expiration date(2)	Grant date present value(3)
Irvin Toole, Jr.	1.8%	9.6%	January 9, 2016	$ 846,384
Forrest E. Wylie(4)	2.9	15.4	January 9, 2016	1,354,214
David E. Wright	2.2	11.6	January 9, 2016	1,015,661
Gerald A. Tywoniuk	1.8	9.6	January 9, 2016	846,384
Lynn T. Wood	0.7	3.9	January 9, 2016	338,554

(1) Assuming all options are exercised.

(2) The expiration date also represents the earliest exercise date, except in limited circumstances such as a change in control.

(3) The present value of the grant at January 9, 2006, the date of grant, using the Black-Scholes option pricing model. The following assumptions were used: volatility 21.86%; risk-free rate of return 4.37%; dividend yield of 0% and exercise in ten years.

(4) Excludes an additional 3.3% grant (potential ownership in LB Pacific LP assuming all options are exercised) for Mr. Wylie's role in sourcing, evaluating, financing and closing the acquisition by LB Pacific, LP of the limited and general partner interests in Pacific Energy Partners, L.P. from The Anschutz Corporation.

Grants under the LBP plan were also made to other key employees of the General Partner and Partnership.

As noted above, we are not obligated to pay any amounts to LB Pacific, LP for the benefits granted or paid to our executives under the plan, although generally accepted accounting principles require that we record an expense over the vesting period with a corresponding increase in the general partners' capital account.

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

The following table sets forth the beneficial ownership of equity securities of Pacific Energy Partners as of January 31, 2006, held by beneficial owners of more than 5% of the units, by directors of our General Partner, by each named executive officer, by our General Partner 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)	2,616,250(5)	8.3%(6)	7,848,750(5)	100%(6)	26.1%(6)
First Reserve GP X Inc.(2)	2,616,250(7)	8.3(8)	7,848,750(7)	100(8)	26.1(8)
LB Pacific, LP(1)	2,616,250	8.3	7,848,750	100	26.1
Tortoise Capital Advisors LLC(9)	2,952,284(10)	9.4			7.4
Tortoise Energy Capital Corporation(9)	1,617,500	5.1			4.0
Kayne Anderson Capital Advisors, LP(11)	1,880,500	6.0			4.7
Richard A. Kayne(11)	1,880,500	6.0			4.7
Pacific Energy GP, LP					
Douglas L. Polson	100,631(12)	*			*
Forrest E. Wylie(13)	508(13)	*			*
Christopher R. Manning	2,616,250(5)	8.3(6)	7,848,750(5)	100(6)	26.1(6)
Joshua L. Collins	2,616,250(5)	8.3(6)	7,848,750(5)	100(6)	26.1(6)
Timothy H. Day	2,616,250(7)	8.3(8)	7,848,750(7)	100(8)	26.1(8)
David L. Lemmon	4,336(12)	*			*
John C. Linehan	3,500(12)	*			*
Jim E. Shamas	5,000(12)	*			*
William L. Thacker	3,000(12)	*			*
Irvin Toole, Jr.(13)	50,938(13)	*			*
David E. Wright(13)	28,916(13)	*			*
Gerald A. Tywoniuk(13)	8,422(13)	*			*
Lynn T. Wood(13)	14,185(13)	*			*
All directors and executive officers as a group (16 persons)	2,862,347	9.1%(14)	7,848,750	100%	26.7%(14)

(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 First Reserve GP X, Inc. is One Lafayette Place, Greenwich, CT 06830.

(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 common and subordinated units shown as beneficially owned by Lehman Brothers Holdings, Inc., Christopher R. Manning and Joshua L. Collins are directly owned by LB Pacific, LP. Lehman Brothers Holdings, Inc. controls LBMB and LBMB Associates III, LLC, which own a 70% limited partner interest in LB Pacific, LP and a 70% membership interest in LB Pacific GP, LLC and shares control of LB Pacific, LP and LB Pacific GP, LLC with First Reserve GP X, Inc.,

and thus may be deemed to have beneficial ownership of the common and subordinated units owned by LB Pacific, LP. Messrs. Manning and Collins are members of the board of directors of the general partner of LB Pacific, LP and principals of Lehman Brothers Merchant Banking Partners III L.P. and may be deemed to share beneficial ownership of the common and subordinated units shown as beneficially owned by LB Pacific, LP. Messrs. Manning and Collins disclaim beneficial ownership of all such units.

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

(7) The common and subordinated units shown as beneficially owned by First Reserve GP X Inc. and Timothy H. Day are directly owned by LB Pacific, LP. First Reserve GP X Inc., which controls First Reserve Pacific Holdings AIV, L.P., which owns a 30% limited partner interest in LB Pacific, LP and a 30% membership interest in LB Pacific GP, LLC and shares control of LB Pacific, LP and LB Pacific GP, LLC with Lehman Brothers Holding, Inc., and thus may be deemed to have beneficial ownership of the common and subordinated units owned by LB Pacific, LP. Mr. Day is a member of the board of directors of the general partner of LB Pacific, LP and is a director of First Reserve Corporation and may be deemed to share beneficial ownership of the common and subordinated units shown as beneficially owned by LB Pacific, LP and First Reserve Pacific Holdings AIV, L.P. Mr. Day disclaims beneficial ownership of such units.

(8) See Footnote (7) with respect to common and subordinated units which may be attributable to First Reserve GP X Inc. and Mr. Day that have been included in the total. Mr. Day disclaims beneficial ownership of all such units.

(9) The address of Tortoise Capital Advisors LLC and Tortoise Energy Capital Corporation is 10801 Mastin Blvd., Suite 222, Overland Park, Kansas 66210.

(10) Includes 1,617,500 common units owned of record by Tortoise Energy Capital Corporation over which Tortoise Capital Advisors has beneficial ownership pursuant to an investment advisory agreement between Tortoise Capital Advisors LLC and Tortoise Energy Capital Corporation.

(11) The address of Kayne Anderson Capital Advisors, L.P. and Richard A. Kayne is 1800 Avenue of the Stars, Second Floor, Los Angeles, CA 90067. Mr. Kayne is chief executive officer and co-founder of Kayne Anderson Capital Advisors, L.P.

(12) Includes 1,000 units with respect to which such the listed beneficial owner has the right to acquire beneficial ownership through vesting of units under the Long-Term Incentive Plan within 60 days of January 31, 2006.

(13) Includes units with respect to which the listed beneficial owner has the right to acquire beneficial ownership through vesting of units under the Long-Term Incentive Plan within 60 days of January 31, 2006, as set forth in the table below. Pursuant to the terms of the Long-Term Incentive Plan, participants can elect to receive fewer units, in exchange for withholding of sufficient units to pay withholding taxes on the vested units. In connection with the vesting, which

occurred on March 1, 2006, certain of the participants elected to receive fewer units, as reflected in the column titled "Net Common Units Acquired."

Name of Beneficial Owner	Common Units Scheduled to Vest on March 1, 2006	Net Common Units Acquired
Forrest E. Wylie	508	508
Irvin Toole, Jr.	752	483
David E. Wright	341	219
Gerald A. Tywoniuk	272	250
Lynn T. Wood	185	107

(14)
See Footnotes (5) and (7) with respect to common and subordinated units which may be attributable to Messrs. Manning, Collins and Day that have been included in the total. Messrs. Manning, Collins and Day disclaim beneficial ownership of all such units.

The following table sets forth the beneficial ownership of equity securities of LB Pacific, LP as of January 31, 2006, held 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	Options to Acquire LB Pacific, LP Partnership Interests(1)
Pacific Energy GP, LP	
Douglas L. Polson	
Forrest E. Wylie	6.2%
Christopher R. Manning	
Joshua L. Collins	
Tim Day	
David L. Lemmon	
John C. Linehan	
Jim E. Shamas	
William L. Thacker	
Irvin Toole, Jr.	1.8
David E. Wright	2.2
Gerald A. Tywoniuk	1.8
Lynn T. Wood	0.7
All directors and executive officers as a group (16 persons)	15.7

(1)
Not exercisable within 60 days of January 31, 2006. Figures represent maximum percentage ownership if all performance targets are achieved.

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 change of control of us.

Equity Compensation Plan Information

The following table sets forth certain information at December 31, 2005 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			1,424,819

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 the Partnership. 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 common units and 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 $1.5 million on the General Partner's 2% general partner interest and LBP would receive approximately $19.4 million on its common and 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.

Ancillary Agreement

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

- Anschutz agreed to enter into a transition services agreement with us;
- Anschutz, 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, Anschutz and one of Anschutz'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.

Lehman Brothers, Inc.

Christopher R. Manning and Joshua L. Collins, 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.

In connection with the purchase and associated financing of the Valero Acquisition, including a private equity offering, public equity offering, debt offering and new credit facility, Lehman Brothers, Inc. and its affiliates provided advisory and underwriting services to us. Additionally, an affiliate of Lehman Brothers, Inc. was a participant in the syndicate that provided our new senior secured credit facility. These agreements with Lehman Brothers, Inc. were reviewed and approved by the Conflicts Committee of the Board of Directors and the fees charged were customary for the types of services provided. For the period from March 3, 2005 through December 31, 2005, we incurred $9.9 million in fees to Lehman Brothers, Inc. and its affiliates, a portion of which was paid to non-affiliated financial institutions in the syndication of the new credit facility and in the public offering of equity.

Cost Reimbursements

General Partner: 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.

Special Agreement: On March 3, 2005, Douglas L. Polson, previously the Chairman of the Board of Directors of Pacific Energy GP, Inc., entered into a Special Agreement and a Consulting Agreement with PEM. In accordance with the Special Agreement, Mr. Polson resigned as Chairman of the Board of Directors of our General Partner effective March 3, 2005. Mr. Polson was paid approximately $0.9 million, representing accrued salary through March 3, 2005, accrued but unused vacation and payment in satisfaction of other obligations under his employment agreement. Pursuant to the Ancillary Agreement, LBP reimbursed us for more than $0.9 million 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 agreed to perform advisory services to PEM from time to time as mutually agreed between Mr. Polson and the Chief Executive Officer of PEM. In consideration for Mr. Polson's services under the Consulting Agreement, which expired on March 3, 2006, Mr. Polson received 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.

LBP and Anschutz: LBP and Anschutz reimbursed us in 2005 for certain costs relating to the LB Acquisition. These included $1.2 million for the Consent Solicitation and $0.3 million for legal and other expenses.

Other Related Party Transactions

Related party balances at December 31, 2005 and 2004 are reflected on the consolidated balance sheets included in the section entitled "Item 8 Financial Statements and Supplementary Data" as follows:

	December 31,	
	2005	2004
	(in thousands)	
Amounts included in accounts receivable:		
Anschutz and affiliates	$	$ 224
Frontier Pipeline Company	142	257
	$ 142	$ 481
Amounts included in "due to related parties":		
Due to Pacific Energy GP, Inc. (predecessor to Pacific Energy GP, LP)	$	$ 533

Prior to March 3, 2005, in the ordinary course of our operations, we engaged in various transactions with Anschutz and its affiliates. These transactions, which are more thoroughly described below, are summarized in the following table for the year ended December 31, 2005, 2004 and 2003:

	For the Year Ended December 31,		
	2005	2004	2003
	(in thousands)		
Revenue:			
Anschutz and affiliates	$ 79	$ 528	$ 1,120
Frontier Pipeline Company	782	880	575
General and administrative expense:			
Anschutz and affiliates	129	316	169
Crude oil purchases:			
Frontier Pipeline Company	1,355		

Revenue from Related Parties

A subsidiary of Anschutz 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 Anschutz subsidiary and a third party, the performance of which required the Anschutz 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 Anschutz 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 Anschutz 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 Anschutz 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 $0.8 million, $0.9 million and $0.6 million for the years ended December 31, 2005, 2004 and 2003, respectively.

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Expenses Paid to Related Parties

Pursuant to an easement agreement between PPS and Union Pacific Corporation ("UPC"), UPC provides us with access to its right-of-way for a portion of Line 2000 in return for an annual rental. Philip F. Anschutz, a director of our General Partner until March 3, 2005, and sole stockholder of Anschutz Company, the indirect parent of our General Partner until that date, is a director of UPC.

From mid-2002 through December 31, 2005, we utilized a financial accounting system owned and provided by Anschutz under a shared services arrangement. In addition, from time to time until mid-2003 we utilized the services of Anschutz's risk management personnel for acquiring our insurance, and until 2004 our surety bonds were issued under Anschutz's bonding line. From January 2003 through December 31, 2005, Anschutz charged us a fee of $0.1 million per year for these services, plus any out-of-pocket costs. The fixed annual fee included all license, maintenance and employee costs associated with our use of the financial accounting system.

In January 2003, we began leasing approximately office space from an affiliate of Anschutz, for a term of five years at an initial annual cost of $0.1 million. This lease terminated in February 2006.

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, 2005 and 2004 and fees billed for other services rendered by KPMG LLP during those periods.

For the Year Ended December 31,	2005	2004
	(in thousands)	
Audit fees	$ 1,260	$ 848
Audit related fees		74
Tax fees		
All other fees		
Total	$ 1,260	$ 922

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	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)
4.2	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)
4.3	Indenture dated September 23, 2005, by and among Pacific Energy Partners, L.P., Pacific Energy Finance Corporation, Pacific Atlantic Terminals LLC, Pacific Energy Group LLC, PEG Canada GP LLC, PEG Canada, L.P., Rocky Mountain Pipeline System LLC, Ranch Pipeline LLC, Pacific Marketing and Transportation LLC, and Wells Fargo Bank, National Association (Incorporated by reference to Pacific Energy Partners, L.P.'s Form 8-K dated September 23, 2005, Exhibit 4.1)
4.4	Registration Rights Agreement, dated September 23, 2005, among the Issuers and the Initial Purchasers (Incorporated by reference to Pacific Energy Partners, L.P.'s Form 8-K dated September 28, 2005, Exhibit 4.3)

10.1	Credit Agreement, dated as of September 30, 2005, among Pacific Energy Partners, L.P., Rangeland Pipeline Company, Bank of America, NA and other lenders party thereto (Incorporated by reference to Pacific Energy Partners, L.P.'s Form 8-K filed on October 6, 2005, Exhibit 10.1)
10.2^	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)
10.3^	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)
10.4^	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)
10.5	Omnibus Agreement (Incorporated by reference to Pacific Energy Partners, L.P.'s Form 10-Q filed on September 5, 2002, Exhibit 10.10)
10.6	First Amendment to Omnibus Agreement (Incorporated by reference to Exhibit 10.1 to Form 8-K filed on March 9, 2005)
10.7^	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))
10.8^	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)
10.9^	Special Agreement between Pacific Energy Management LLC and Douglas L. Polson dated March 3, 2005 (Incorporated by reference to Pacific Energy Partners, L.P.'s Form 10-K filed on March 15, 2005, Exhibit 10.14)
10.10^	Consulting Agreement between Pacific Energy Management LLC and Douglas Polson dated March 3, 2005 (Incorporated by reference to Pacific Energy Partners, L.P.'s Form 10-K filed on March 15, 2005, Exhibit 10.15)
10.11^	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)
10.12^	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)
10.13^	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))
10.14	Ancillary Agreement by and among PPS Holding Company, The Anschutz Corporation, LB Pacific, LP, Pacific Energy Partners, L.P. and Pacific Energy GP, Inc. (Incorporated by reference to Exhibit 10.1 to Form 8-K filed November 3, 2004)
10.15	Director Compensation Summary Sheet (Incorporated by reference to Exhibit 10.1 to Form 8-K filed February 7, 2006)
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: 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, 2006

By: /s/ GERALD A. TYWONIUK

Gerald A. Tywoniuk
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)
March 10, 2006

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, 2006	/s/ JOSHUA L. COLLINS Joshua L. Collins	Director
March 10, 2006	/s/ TIMOTHY H. DAY Timothy H. Day	Director
March 10, 2006	/s/ DAVID L. LEMMON David L. Lemmon	Director
March 10, 2006	/s/ JOHN C. LINEHAN John C. Linehan	Director
March 10, 2006	/s/ CHRISTOPHER R. MANNING Christopher R. Manning	Director
March 10, 2006	/s/ DOUGLAS L. POLSON Douglas L. Polson	Director
March 10, 2006	/s/ JIM E. SHAMAS Jim E. Shamas	Director
March 10, 2006	/s/ WILLIAM L. THACKER William L. Thacker	Director
March 10, 2006	/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, 2005 and 2004, 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, 2005. 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, 2005 and 2004, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2005, 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, 2005, 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, 2006 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, 2006

PACIFIC ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

December 31, 2005 and 2004

	2005	2004
	(in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 18,064	$ 23,383
Crude oil sales receivable	95,952	28,609
Transportation and storage accounts receivable	30,100	20,137
Canadian goods and services tax receivable	8,738	7,632
Insurance proceeds receivable (note 4)	9,052	
Crude oil and refined products inventories (note 2)	20,192	9,174
Prepaid expenses	7,489	4,159
Other	2,528	2,451
Total current assets	192,115	95,545
Property and equipment, net (note 5)	1,185,534	718,624
Intangible assets, net (note 6)	69,180	37,894
Investment in Frontier (note 7)	8,156	7,886
Other assets, net	21,467	9,956
	$ 1,476,452	$ 869,905
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 43,859	$ 15,272
Accrued crude oil purchases	96,651	27,231
Line 63 oil release reserve (note 4)	4,448	
Accrued interest	4,929	1,124
Due to related parties (note 8)		533
Other	6,300	3,885
Total current liabilities	156,187	48,045
Senior notes and credit facilities, net (note 9)	565,632	357,163
Deferred income taxes (note 11)	35,771	34,556
Environmental liabilities (note 12)	16,617	7,269
Other liabilities	4,006	406
Total liabilities	778,213	447,439
Commitments and contingencies (notes 12, 13 and 14)		
Partners' capital (note 15):		
Common unitholders (31,448,931 and 19,158,747 units outstanding at December 31, 2005 and 2004, respectively)	644,589	361,427
Subordinated unitholders (7,848,750 and 10,465,000 units outstanding at December 31, 2005 and 2004, respectively)	24,758	41,521
General Partner interest	12,535	6,280
Undistributed employee long-term incentive compensation		116
Accumulated other comprehensive income	16,357	13,122
Net partners' capital	698,239	422,466

	2005	2004
	$ 1,476,452	$ 869,905

See accompanying notes to consolidated financial statements.

PACIFIC ENERGY PARTNERS, L. P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

Years ended December 31, 2005, 2004 and 2003

	2005	2004	2003
	(in thousands, except per unit amounts)		
Revenues:			
Pipeline transportation revenue	$ 116,648	$ 108,395	$ 101,811
Storage and terminaling revenue	51,986	37,577	12,711
Pipeline buy/sell transportation revenue	35,671	18,640	
Crude oil sales, net of purchases of $623,115, $402,283 and $358,454 in 2005, 2004 and 2003, respectively	19,997	16,787	21,293
	224,302	181,399	135,815
Cost and Expenses:			
Operating	104,397	85,286	61,046
General and administrative	18,472	15,400	13,705
Accelerated long-term incentive plan compensation expense (note 18)	3,115		
Line 63 oil release costs (note 4)	2,000		
Transaction costs (notes 8 and 17)	1,807		
Depreciation and amortization	29,406	24,173	18,865
	159,197	124,859	93,616
Share of net income (loss) of Frontier (note 7):			
Income before rate case and litigation expense	1,757	1,328	1,459
Rate case and litigation expense			(1,621)
Share of net income (loss) of Frontier	1,757	1,328	(162)
Write-down of idle property (note 2)	(450)	(800)	
Operating income	66,412	57,068	42,037
Interest and other income	1,119	1,032	479
Write-off of deferred financing costs and interest rate swap termination expense (note 10)		(2,901)	
Interest expense	(26,720)	(19,209)	(17,487)
Income before income taxes	40,811	35,990	25,029
Income tax (expense) benefit (note 11):			
Current	(1,252)	(326)	
Deferred	89	65	
	(1,163)	(261)	
Net income	$ 39,648	$ 35,729	$ 25,029
Net income (loss) for the general partner interest (note 17)	$ (978)	$ 715	$ 501

	2005	2004	2003
Net income for the limited partner interests	$ 40,626	$ 35,014	$ 24,528
Net income per limited partner unit:			
Basic	$ 1.25	$ 1.23	$ 1.10
Diluted	$ 1.25	$ 1.23	$ 1.09
Weighted average limited partner units outstanding:			
Basic	32,381	28,406	22,328
Diluted	32,414	28,488	22,540

See accompanying notes to consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
Years ended December 31, 2005, 2004 and 2003
(in thousands)

	Limited Partner Units		Limited Partner Amounts					
	Common	Subordinated	Common	Subordinated	General Partner Interest	Undistributed Employee Long-Term Incentive Compensation	Accumulated Other Comprehensive Income (Loss)	Total
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		1,955			133,671
Redemption of common units held by general partner	(1,727)		(40,780)					(40,780)
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)
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		2,690			128,571
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)
Changes in fair value of interest rate and crude oil hedging derivatives							5,422	5,422
Foreign currency translation adjustment							13,308	13,308
Balance, December 31, 2004	19,159	10,465	$ 361,427	$ 41,521	$ 6,280	$ 116	$ 13,122	$ 422,466
Net income			29,027	11,599	(978)			39,648
Distributions to partners			(45,458)	(19,981)	(1,336)			(66,775)
Issuance of common units, net of fees and offering expenses	9,533		288,960		6,116			295,076
General partner contribution					2,407			2,407
Employee compensation under long-term incentive plan						2,886		2,886
Issuance of common units pursuant to long-term incentive plan	99		1,545		31	(3,002)		(1,426)
Exercise of unit options pursuant to long-term incentive plan	42		707		15			722
Conversion of subordinated units to common units	2,616	(2,616)	8,381	(8,381)				
Changes in fair value of crude oil and foreign currency hedging contracts							(269)	(269)
Foreign currency translation adjustment							3,504	3,504
Balance, December 31, 2005	31,449	7,849	$ 644,589	$ 24,758	$ 12,535	$	$ 16,357	$ 698,239

See accompanying notes to consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years ended December 31, 2005, 2004 and 2003

	2005	2004	2003
		(in thousands)	
Net income	$ 39,648	$ 35,729	$ 25,029
Change in fair value of interest rate hedging derivatives		5,436	1,939
Change in fair value of crude oil hedging derivatives	(74)	(14)	(172)
Change in fair value of foreign currency hedging derivatives	(195)		
Change in foreign currency translation adjustment	3,504	13,308	
Comprehensive income	$ 42,883	$ 54,459	$ 26,796

See accompanying notes to consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years ended December 31, 2005, 2004 and 2003

	2005	2004	2003
		(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 39,648	$ 35,729	$ 25,029
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	29,406	24,173	18,865
Amortization of debt issue costs	2,027	1,537	1,028
Write-off of deferred financing costs		2,321	
Write-down of idle property	450	800	
Non-cash employee compensation under long-term incentive plan	2,886	2,076	3,233
Deferred tax expense (benefit)	(89)	(65)	
Share of net (income) loss of Frontier	(1,757)	(1,328)	162
Other non-cash items	220		
Distribution from (contribution to) Frontier, net	1,317	(44)	1,755
Net changes in operating assets and liabilities:			
Crude oil sales receivable	(66,968)	5,157	(9,609)
Transportation and storage accounts receivable	(9,951)	(1,311)	(6,260)
Insurance proceeds receivable	(9,052)		
Other current assets and liabilities	(14,901)	(9,337)	557
Accounts payable and other accrued liabilities	29,453	(565)	726
Accrued crude oil purchases	68,974	(4,370)	7,217
Line 63 oil release reserve	4,448		
Other non-current assets and liabilities	(3)	2,453	20
NET CASH PROVIDED BY OPERATING ACTIVITIES	76,108	57,226	42,723
CASH FLOWS FROM INVESTING ACTIVITIES:			
Acquisitions	(462,553)	(138,701)	(169,740)
Additions to property and equipment	(51,717)	(16,520)	(10,892)
Other	1,519	(731)	300
NET CASH USED IN INVESTING ACTIVITIES	(512,751)	(155,952)	(180,332)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Issuance of common units, net of fees and offering expenses	288,960	125,881	131,716
Capital contributions from the general partner	8,569	2,720	1,986
Redemption of common units held by the general partner, net of underwriter's fees			(40,780)
Net proceeds from senior notes offerings	170,889	240,932	
Repayment of term loan		(225,000)	
Proceeds from credit facilities	283,502	140,922	166,000
Repayment of credit facilities	(249,466)	(115,253)	(93,000)
Deferred bank debt financing costs	(4,573)	(1,227)	
Distributions to partners	(66,775)	(56,518)	(42,115)
Issuance of common units pursuant to exercise of unit options	707		
Change in balance due from or to related parties	(533)	(47)	(372)
NET CASH PROVIDED BY FINANCING ACTIVITIES	431,280	112,410	123,435
Effect of exchange rates on cash	44		
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(5,319)	13,684	(14,174)
CASH AND CASH EQUIVALENTS, beginning of year	23,383	9,699	23,873

		2005		2004		2003
CASH AND CASH EQUIVALENTS, end of year	$	18,064	$	23,383	$	9,699
Supplemental disclosures:						
Cash paid for interest	$	22,462	$	19,881	$	16,252
Taxes paid	$	665	$	125	$	
Non-cash financing and investing activities:						
Additions to equipment	$		$		$	204

See accompanying notes to consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND BASIS OF PRESENTATION

Organization

Pacific Energy Partners, L.P., a Delaware limited partnership, was formed in February 2002 and completed its initial public offering of common units representing limited partner units on July 26, 2002. Pacific Energy Partners, L.P. and its subsidiaries (collectively the "Partnership") are engaged principally in the business of gathering, transporting, storing and distributing crude oil, refined products and other related products. The Partnership generates revenue primarily by transporting such commodities on its pipelines, by leasing storage capacity in its storage tanks, and by providing other terminaling services. The Partnership also buys and sells crude oil, activities that are generally complementary to its other crude oil operations. The Partnership conducts its business through two business units, the West Coast Business Unit, which includes activities in California and the Philadelphia, Pennsylvania area, and the Rocky Mountain Business Unit, which includes activities in five Rocky Mountain states and Alberta, Canada.

The Partnership is managed by its general partner, Pacific Energy GP, LP, a Delaware limited partnership (the "General Partner"), 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 ("Anschutz"). On March 3, 2005, Anschutz sold all of its interest in Pacific Energy GP, Inc. to LB Pacific, LP ("LBP"), which was formed by the Lehman Brothers Merchant Banking Group ("LBMB") in connection with the purchase (see "Note 8 Related Party Transactions"). Pacific Energy GP, LP is managed by its general partner, Pacific Energy Management LLC ("PEM"), a Delaware limited liability company, thus the officers and Board of Directors of PEM manage the business affairs of the Partnership and its General Partner. The Partnership's General Partner does not receive any management fee or other compensation in connection with its management of the Partnership's business, but is entitled to reimbursement for all direct and indirect expenses incurred on the Partnership's behalf.

The Partnership holds 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 Atlantic Terminals LLC ("PAT"), which was formed for the purpose of acquiring the California and East Coast terminal assets the Partnership purchased on September 30, 2005 as part of the acquisition of assets from Valero, L.P. (see "Note 3 Acquisitions");

(iv) Pacific Marketing and Transportation LLC ("PMT"), owner of the PMT gathering system and marketer of crude oil;

(v) Rocky Mountain Pipeline System LLC ("RMPS"), owner of the Western Corridor and Salt Lake City Core systems, and which acquired the West Pipeline system (which is now known as the Rocky Mountain Products Pipeline) on September 30, 2005 as part of the acquisition of assets from Valero, L.P.; and

(vi) Ranch Pipeline LLC ("RPL"), owner of a 22.22% partnership interest in Frontier Pipeline Company ("Frontier"), a Wyoming general partnership.

The Partnership holds 100% interest in PEG Canada GP LLC ("PEG Canada GP"), the general partner of PEG Canada, L.P. ("PEG Canada"), the holding company of the Partnership's Canadian subsidiaries. The Partnership owns 100% of the limited and general partner interests in PEG Canada, whose 100% owned subsidiaries consist of:

(i) Rangeland Pipeline Company ("RPC"), which owns 100% of Aurora Pipeline Company Ltd. ("Aurora") and a partnership interest in Rangeland Pipeline Partnership ("Rangeland Partnership");

(ii) Rangeland Northern Pipeline Company ("RNPC"), which owns the remaining partnership interest in Rangeland Partnership; and

(iii) Rangeland Marketing Company ("RMC").

Rangeland Partnership owns all of the assets that make up the Rangeland pipeline system except the Aurora pipeline, which is owned by Aurora.

The Partnership also owns 100% of Pacific Energy Finance Corporation, which was organized for the purpose of co-issuing the Partnership's senior notes.

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, PT, PAT and PMT. The Rocky Mountain Business Unit includes RMPS, RPL and PEG Canada and its Canadian subsidiaries RPC, Aurora, RNPC, RMC and Rangeland Partnership. Information relating to these two segments is summarized in "Note 20 Segment Information".

Basis of Presentation

The accompanying financial statements and related notes present the Partnership's (including all of its wholly-owned subsidiaries) consolidated financial position as of December 31, 2005 and 2004, and the consolidated results of the Partnership's operations, cash flows, changes in partners' capital and comprehensive income for the years ended December 31, 2005, 2004 and 2003. All significant intercompany balances and transactions have been eliminated during the consolidation process. Certain reclassifications were made to prior periods to conform to the current period presentation. Investments in affiliates, over which the Partnership has significant influence, are accounted for by the equity method.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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.

Revenue Recognition

Revenue from pipeline transportation services is recognized upon delivery of the product 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. Revenue from buy/sell transactions is recognized on a net basis. Revenue is recognized when the commodity is delivered to the customer.

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.

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 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 West and East Coast products terminals are not regulated utilities, nor is the PMT gathering system, which is a proprietary intrastate operation.

The Western Corridor and Salt Lake City Core systems are common carrier pipelines that transport oil under cost-based tariffs under the jurisdiction of the Federal Energy Regulatory Commission ("FERC") and the Wyoming Public Service Commission ("WPSC"). The Rocky Mountain Products Pipeline that was acquired as part of the Valero Acquisition is a common carrier system that transports products under market-based FERC tariffs, except for one FERC regulated cost-based segment, and under cost-based tariffs under the jurisdiction of the states of Wyoming and Colorado.

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 and Utilities Board ("EUB"). The Aurora pipeline is subject to the jurisdiction of 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.

Concentration of Customers and Credit Risk

A substantial portion of the West Coast transportation and storage business in 2005, 2004 and 2003 was with four customers who individually accounted for more that 10% of West Coast transportation and storage revenue. Collectively, these four customers accounted for approximately 60%, 73% and 76% of total West Coast transportation and storage revenue in 2005, 2004 and 2003, respectively. Two of these customers, Chevron and Shell Trading Company, who collectively accounted for approximately 32%, 46% and 47% of 2005, 2004 and 2003 transportation and storage revenue, respectively, have executed ten-year ship or pay transportation agreements expiring in 2009 whereby they have committed to ship minimum volumes that represent approximately 61% of their actual 2005 volumes transported on the Partnership's West Coast pipelines.

A substantial portion of the Partnership's Rocky Mountain pipeline transportation and storage business in 2005, 2004 and 2003 was with two customers who individually accounted for more that 10% of Rocky Mountain transportation revenue. Collectively, these two customers accounted for approximately 36%, 40% and 50% of total Rocky Mountain transportation revenue in 2005, 2004 and 2003, respectively. In addition, for the Partnership's Canadian buy/sell transportation revenue, in 2005 three customers accounted for 50% of the Partnership's Canadian net sales revenue and in 2004 two customers accounted for approximately 60% of the Partnership's Canadian net sales revenue. In 2005, three suppliers accounted for 58% of the Partnership's Canadian net purchase contracts and in 2004 one supplier accounted for 66% of the Partnership's Canadian net purchase contracts. Each of these customers and suppliers individually accounted for more that 10% of the Partnership's Canadian buy/sell transportation revenue and net purchase contracts.

Although the above concentration could affect the Partnership's overall exposure to credit risk, management believes that the risk is minimal given that a majority of its business is conducted with large, 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.

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 the Partnership's gathering and marketing activities. The Partnership's gathering and marketing activities can generally be described as high volume and low margin activities. Transportation and storage accounts receivable are from shippers who transport crude on our pipelines and customers who lease our storage capacity. The Partnership makes a determination of the amount, if any, 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 monitors 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 accounts receivable balances to identify past due amounts and analyze the reasons such amounts have not been collected. In many instances, such delays involve billing discrepancies or disputes as to the appropriate price, volumes or quality of crude oil delivered or exchanged. The Partnership has an insignificant amount for allowances for doubtful accounts as of December 31, 2005, 2004 and 2003.

Crude Oil and Refined Products Inventories

Crude oil and refined products inventories are valued at the lower of cost or market with cost determined using an average cost method. The inventory balance is subject to downward adjustment if 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, 2005 and 2004, and 2003, capitalized interest was $1.1 million, $0.4 million, and $0.1 million, respectively. In addition, costs incurred to extend the useful lives of assets 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.

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. 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. The Partnership recorded impairment expense of $0.5 million and $0.8 million associated with idle Pacific Terminals property in 2005 and 2004, respectively.

Asset Retirement Obligations

The Partnership has determined that it is obligated by contractual or regulatory requirements to remove facilities or perform remediation upon retirement of certain of its assets. However, the Partnership is not able to reasonably determine the fair value of the asset retirement obligations for its pipelines and storage tanks, since the range of future dismantlement and removal dates are indeterminate.

In order to determine a removal date for the Partnership's gathering lines and related surface assets, reserve information regarding the production life of the specific field is required. The Partnership is not a producer of the oil field reserves, and therefore does not have access to adequate forecasts that predict the timing of expected production for existing reserves on those fields in which the Partnership gathers crude oil. In the absence of such information, the Partnership is not able to make a reasonable estimate of when the dismantlement and removal of its gathering assets will be required. With regard to the Partnership's trunk and interstate pipelines and their related surface assets, it is not possible to predict when demand for transportation of the related products will cease. The Partnership's right-of-way agreements allow it to maintain the right-of-way rather than remove the pipe. In addition, the Partnership believes its trunk pipelines can be put into alternative uses.

The Partnership will record such asset retirement obligations in the period in which sufficient information becomes available for it to reasonably estimate the settlement date and amount of its retirement obligations.

Investment in Frontier

The Partnership's 22% investment in Frontier is accounted for using the equity method of accounting. Under the equity method, an 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.

Deferred Financing Costs

Costs incurred in connection with the issuance of long-term debt are capitalized and amortized using the effective interest method. Costs incurred in connection with the issuance and amendments to our credit facilities are capitalized and amortized using the straight line methods over the term of the related facility. Unamortized debt issue costs may be written-off in conjunction with the refinancing or termination of the applicable debt arrangement prior to its scheduled maturity. We capitalized $7.9 million and $5.9 million of such costs in 2005 and 2004, respectively. In addition, during 2004 we wrote off $2.3 million of unamortized costs relating to the early termination of debt.

Environmental Liabilities

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 can be reasonably estimated. To the extent environmental liabilities are assumed in acquisitions, the Partnership records an estimate of such costs at the date of acquisition. 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. The Partnership monitors the balance of accrued undiscounted environmental liabilities on a regular basis and may make adjustments to the initial estimates recorded, from time to time, to reflect changing circumstances.

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 by the Partnership from Canada into the U.S. may subject the Partnership 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 their 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 generally have no responsibility to file Canadian tax returns.

Income taxes for the Partnership's Canadian subsidiaries 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 of a change in tax rates on deferred tax assets and liabilities is recognized in operations in the period that includes the enactment date. The Partnership intends to repatriate its Canadian subsidiaries' earnings in the future and accordingly has recorded a provision for Canadian withholding taxes.

Derivative Instruments

The Partnership uses certain derivative instruments to hedge its exposure to commodity price, interest rate and foreign exchange rate risks. The Partnership records all derivative instruments on the balance sheet as either assets or liabilities measured at their fair value under the provisions of Statement of Financial Accounting Standards No. 133 ("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 are not highly effective in offsetting changes in cash flows of hedged items. (See "Note 16 Derivative Financial Instruments" for further discussion).

The Partnership formally documents at inception the hedging relationship and its risk management objective and strategy for undertaking the hedge, the hedging instrument used, the nature of the risk being hedged, how the hedging instrument's effectiveness in offsetting the hedged risk will be assessed and the method of measuring such ineffectiveness. On a continuing basis, the Partnership assesses whether the derivative instruments that are used as hedges are highly effective in offsetting changes in fair values or cash flows that are being hedged. If it is determined that a derivative instrument ceases to be a highly effective hedge, then the Partnership will discontinue hedge accounting prospectively.

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."

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. Following is a reconciliation of the basic weighted average limited partner units to diluted weighted average limited partner units.

	Year Ended December 31,		
	2005	2004	2003
	(in thousands)		
Basic weighted average limited partner units	32,381	28,406	22,328
Effect of restricted units	23	67	202
Effect of unit options	10	15	10
Diluted weighted average limited partner units	32,414	28,488	22,540

Allocation of Net Income

Net income is allocated to the Partnership's general partner and limited partners based on their respective interests in the Partnership. The Partnership's general partner has also been directly charged with specific costs that it assumed in connection with its acquisition by LBP and for which neither the Partnership nor the limited partners are responsible (see "Note 17 Allocation of Net Income").

Restricted Units and Unit Options

As permitted under Statement of Financial Accounting Standards No. 123 ("SFAS 123"), "Accounting for Stock-Based Compensation," the Partnership 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 123, "Accounting for Stock-Based Compensation," net income would have been reduced less than $0.1 million in each of 2005, 2004 and 2003 and the effect on earnings per limited partner unit would have been less than $0.01 per limited partner unit in each of 2005, 2004 and 2003.

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. There were no stock options or restricted stock units outstanding as of December 31, 2005 (see "Note 18 Long-Term Incentive Plan"). The Partnership will adopt SFAS 123R on January 1, 2006 for future grants.

In December 2004, the FASB issued Statement of Financial Accounting Standards No. 153, *Exchanges of Nonmonetary Assets* ("SFAS 153"). SFAS 153 addresses the measurement of exchanges of certain nonmonetary assets (except for certain exchanges of products or property held for sale in the ordinary course of business). It amends APB Opinion No. 29, *Accounting for Nonmonetary Exchanges*, and requires that nonmonetary exchanges be accounted for at the fair value of the assets exchanged, with gains or losses being recognized, if the fair value is determinable within reasonable limits and the transaction has commercial substance, as defined in SFAS 153. The Partnership adopted SFAS 153 on July 1, 2005, and the adoption did not have a material impact on the consolidated financial statements.

On March 30, 2005 the FASB issued FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations*("FIN 47"), to clarify the term *conditional asset retirement obligation* as that term is used in FASB Statement No. 143, *Accounting for Asset Retirement Obligations*. The Interpretation also clarifies when an entity has sufficient information to reasonably estimate the fair value of an asset retirement obligation. FIN 47 was effective for us as of December 31, 2005. The adoption of FIN 47 did not have a material impact on the Partnership's financial statements.

In May 2005, the FASB issued Statement of Financial Accounting Standards No. 154, *Accounting Changes and Error Corrections* ("SFAS 154"). SFAS 154 replaces APB No. 20, *Accounting Changes,* and FASB Statement No. 3, *Reporting Changes in Interim Financial Statements.* The Statement changes the accounting for, and reporting of, a change in accounting principle. SFAS 154 requires retrospective application to prior period's financial statements of voluntary changes in accounting principle and changes required by new accounting standards when the standard does not include specific transition provisions, unless it is impracticable to do so. SFAS 154 is effective for accounting changes and corrections of errors in fiscal years beginning after December 15, 2005. If required, the Partnership will apply the provisions of SFAS 154 in future periods.

In September 2005, the Emerging Issues Task Force ("EITF") issued Issue No. 04-13 ("EITF 04-13"), *Accounting for Purchases and Sales of Inventory with the Same Counterparty*. The issues addressed by the EITF are (i) the circumstances under which two or more exchange transactions involving inventory with the same counterparty should be viewed as a single exchange transaction for the purposes of evaluating the effect of APB No. 29; and (ii) whether there are circumstances under which nonmonetary exchanges of inventory within the same line of business should be recognized at fair value. EITF 04-13 is effective for new arrangements entered into in the reporting periods beginning after March 15, 2006, and to all inventory transactions that are completed after December 15, 2006, for arrangements entered into prior to March 15, 2006. The Partnership is in the process of determining the impact of EITF 04-13 on its financial statements, but does not expect it to have a material impact on its financial statements.

3. ACQUISITIONS

Acquisition Of Assets From Valero, L.P.

On September 30, 2005, the Partnership completed the purchase of certain terminal and pipeline assets from various subsidiaries of Valero, L.P. (the "Sellers") for an aggregate purchase price of $455.0 million, plus $11.5 million for the assumption of certain legal, environmental and operating liabilities and $3.7 million for closing costs (the "Valero Acquisition"). Valero, L.P. was required to divest these assets pursuant to an order from the Federal Trade Commission in connection with its acquisition of the Kaneb group of companies. The purchased assets consist of (i) the Martinez and Richmond terminals in the San Francisco, California area, (ii) the North Philadelphia, South Philadelphia and Paulsboro, New Jersey, terminals in the Philadelphia, Pennsylvania area, and (iii) a 550-mile refined products pipeline with four terminals in the U.S. Rocky Mountains (the "Valero Assets"). The Valero Acquisition was funded through a combination of the proceeds from a private placement of 4.3 million common units, a public equity offering of 5.2 million common units, a private placement of $175 million of senior unsecured notes, and borrowings under the Partnership's new revolving credit facility (See "Note 9 Long-term Debt" and "Note 15 Partner's Capital" for further discussion on these financing arrangements).

The Martinez and Richmond terminals currently have 4.1 million barrels of combined storage capacity. The terminals handle refined products, blend stocks and crude oil, and are connected to a network of owned and third-party pipelines that carry crude oil and light products to and from area refineries. These terminals also receive and deliver crude oil and light products by marine vessel or barge. The Richmond terminal has a rail spur for delivery and receipt of light products and a truck rack for product delivery.

The North Philadelphia, South Philadelphia and Paulsboro terminals handle refined products and have a combined storage capacity of 3.1 million barrels. The terminals receive product via connections to third party pipelines and have truck racks for deliveries. The North Philadelphia and Paulsboro terminals can also deliver and receive products by marine vessel or barge.

The 550-mile Rocky Mountain Products Pipeline, formerly known as the West Pipeline System, consists of 550 miles of pipeline extending from Casper, Wyoming, east to Rapid City, South Dakota, and south to Colorado Springs, Colorado. There are products terminals at Rapid City, South Dakota, Cheyenne, Wyoming, and Denver and Colorado Springs, Colorado, with a combined storage capacity of 1.7 million barrels. The pipeline system has various segments with different receipt and delivery points.

The majority of the Rocky Mountain Products Pipeline was constructed in 1948, with extensions to Rapid City and Colorado Springs added in the 1960's. The South Philadelphia Terminal was constructed in 1938, the Richmond and Paulsboro terminals were constructed in 1953, and the Martinez and North Philadelphia terminals were constructed in 1973. Many improvements and facility additions have been made since the original startup of the operations. Additional tankage has been constructed and pipeline system and terminal improvements have been made over the years since their initial startup.

The Partnership has integrated the operations, maintenance, marketing and business development of the Rocky Mountain Products Pipeline with its existing pipeline activities in the Rocky Mountain Business Unit. It has similarly integrated the San Francisco area and Philadelphia area terminals with its existing pipeline and terminal activities in its West Coast Business Unit.

The Partnership did not acquire accounting software or hardware with the acquired assets. The Partnership has acquired and is implementing software associated with the complex task of volumetric and revenue accounting for the acquired assets, and uses its existing financial accounting software for other accounting functions. In addition, the Partnership did not acquire the pipeline control center or the software and other operating systems required for the Rocky Mountain Products Pipeline, and has installed new operating systems that are now being operated out of its Long Beach pipeline control center. The Seller agreed to provide all of these accounting, control center and operating services to the Partnership on a transition basis.

The acquired assets comprise only a portion of the total pipeline and terminal assets owned and operated by the Sellers in North America. The Sellers have other substantial pipeline and terminal assets that the Partnership did not acquire that are, or have been, operated and managed by the Seller's existing management team and operating and marketing staff. The acquired assets were not historically operated by the Sellers as a separate division or subsidiary. The Sellers, and prior to its merger with Valero, L.P., Kaneb Pipeline Partners, L.P. ("Kaneb"), operated these assets as part of its more extensive transportation and terminalling and refined products operations. As a result, neither the Sellers nor Kaneb maintained complete and separate financial statements for these assets as an independent business unit. The Partnership is making significant changes to the assets, and intends additional changes in the future, resulting in significant differences in operations and revenue generation. Additionally, differences in the Partnership's operating and marketing approach may result in it obtaining different productivity levels, results of operations and revenues than those historically achieved by the Sellers and Kaneb.

At the closing of the acquisition, the Partnership hired 76 of the Seller's employees directly involved in the operation of the acquired assets, including certain field level managerial and supervisory employees, operators, technicians, and engineers/project coordinators. The Partnership has hired additional accounting, environmental, engineering, pipeline controllers and technical staff to support the acquired assets.

The acquisition was accounted for as an acquisition of assets, and not as an acquisition of a continuing business operation.

The consolidated statements of income include the results of the acquired assets from their acquisition date. 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 and assumed liabilities:		
Purchase price	$	455,000
Transaction costs		3,740
Assumed liabilities		11,524
Total consideration and assumed liabilities	$	470,264
Purchase price allocation:		
Land and improvements	$	41,672
Storage tanks, pipelines and related equipment		396,696
Inventory		176
Intangible assets		31,720
Total	$	470,264

The Partnership is depreciating the purchased assets over their estimated useful lives of three to forty years based on the type of assets, which lives are similar to the Partnership's existing assets. Intangible assets are amortized over their estimated useful lives, which range from 15 to 40 years.

Purchase Of Crude Oil and Contracts

On July 1, 2005, Pacific Marketing and Transportation LLC, a wholly owned subsidiary of the Partnership, purchased certain crude oil contracts and crude oil inventories for approximately $3.8 million plus contingent payments over the next three and one-half years based on specified performance criteria. The Partnership will capitalize any such contingent payments as intangible assets and amortize them over three years.

Canadian Acquisitions

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. ("Aurora"), 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 these companies 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 borrowings of Cdn$45 million. The acquisition was accounted for as an acquisition of assets.

On June 30, 2004, the Partnership completed the acquisition of the MAPL pipeline from Imperial Oil. The MAPL pipeline is located in Alberta, Canada, and connects with the Rangeland pipeline system. 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 credit facility.

Following the acquisition, the MAPL pipeline assets were integrated into and are now operated as part of the Rangeland system.

Based upon independent appraisals of the fair values of the Rangeland and MAPL assets, the following is a summary of the consideration paid and purchase price allocation (U.S.$ in thousands):

Consideration and assumed liabilities:		
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 and assumed liabilities	$	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. 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, and was treated as an asset purchase. 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 and assumed liabilities:		
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 and assumed liabilities	$	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

4. LINE 63 OIL RELEASE RESERVE

On March 23, 2005, a release of approximately 3,400 barrels of crude oil occurred on Line 63 when it was severed as a result of a landslide induced by heavy rainfall in the Pyramid Lake area of Los Angeles County. Over the period March 2005 through anticipated completion in June 2007, the Partnership expects to incur an estimated total of $25.6 million for oil containment and clean-up of the impacted areas, future monitoring costs, potential third-party claims and penalties, and other costs, excluding pipeline repair costs. As of December 31, 2005, the Partnership had incurred approximately $19.0 million of the total expected remediation costs related to the oil release for work performed through that date. The Partnership estimates that $4.4 million of the remaining remediation costs will be incurred in 2006 and $2.2 million (included in "Other liabilities" in the accompanying balance sheet) will be incurred in 2007. Additionally, in 2005 the Partnership expensed $0.7 million for the repair of Line 63 and incurred $2.2 million of Line 63 capital improvements.

The Partnership has a pollution liability insurance policy with a $2.0 million per-occurrence deductible that covers containment and clean-up costs, third-party claims and penalties. The insurance carrier has, subject to the terms of the insurance policy, acknowledged coverage of the incident and is processing and paying invoices related to the clean-up. The Partnership believes that, subject to the $2.0 million deductible, it will be entitled to recover substantially all of its clean-up costs and any third-party claims associated with the release. The Partnership's insurance coverage will not cover the cost to repair the pipeline. As of December 31, 2005, the Partnership has recovered $12.3 million from insurance and recorded receivables of $11.3 million for future insurance recoveries it deems probable, of which $2.2 million is considered long-term and is included in "Other assets, net" in the accompanying consolidated balance sheet.

The Partnership recorded $2.0 million in net costs in "Line 63 oil release costs" in the accompanying condensed consolidated financial statements for the year ended December 31, 2005. The $2.0 million net oil release costs consist of the $25.6 million of accrued costs relating to the release, net of insurance recovery of $12.3 million and accrued insurance receipts of $11.3 million.

Effective August 1, 2005, with the California Public Utilities Commission (the "CPUC") approval, the Partnership began collecting a temporary surcharge of $0.10 per barrel on its Line 63 long-haul tariff rates to recover its uninsured costs relating to this release together with other costs incurred or to be incurred as a result of problems caused by rain-related earth movement and stream erosion. The Partnership was required under the terms of the CPUC decision that approved the collection of the surcharge, to substantiate in subsequent advice letter filings with the CPUC that the actual costs incurred by the Partnership were necessary and reasonable and otherwise recoverable. The Partnership filed its advice letter on January 27, 2006, which was approved by the CPUC on February 22, 2006.

The foregoing estimates are based on facts known at the time of estimation and the Partnership's assessment of the ultimate outcome. Among the many uncertainties that impact the estimates are the necessary regulatory approvals for, and potential modification of, remediation plans, the ongoing assessment of the impact of soil and water contamination, changes in costs associated with environmental remediation services and equipment, and the possibility of third-party legal claims giving rise to additional expenses. Therefore, no assurance can be made that costs incurred in excess of this provision, if any, would not have a material adverse effect on the Partnership's financial condition, results of operations, or cash flows, though the Partnership believes that most, if not all, of any such excess cost, to the extent attributable to clean-up and third-party claims, would be recoverable through insurance. As new information becomes available in future periods, the Partnership may change its provision and recovery estimates.

5. PROPERTY AND EQUIPMENT

Property and equipment consists of the following amounts:

	December 31,	
	2005	2004
	(in thousands)	
Pipelines and tanks	$ 922,946	$ 578,540
Land and land improvements	105,941	73,068
Station and pumping equipment	117,991	75,641
Buildings	15,736	13,580
Other	33,224	26,511
Construction in progress	75,568	15,998
	1,271,406	783,338
Less accumulated depreciation	(120,003)	(92,526)
	1,151,403	690,812
Displacement oil, pipeline linefill and minimum tank inventory	34,131	27,812
	$ 1,185,534	$ 718,624

Depreciation expense for each of the three years in the period ended December 31, 2005, was $27.4 million, $23.4 million and $18.2 million, respectively.

6. INTANGIBLE ASSETS

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 assesses 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, 2005 and 2004 was approximately 31.0 years and 38.5 years, respectively. Amortization expense on amortizable intangible assets was $2.0 million, $0.8 million and $0.6 million for the years ended December 31, 2005, 2004 and 2003, respectively. Intangible assets included in the accompanying balance sheet consist of the following:

	December 31,	
	2005	2004
	(in thousands)	
Customer relationships and contracts	$ 59,459	$ 37,788
Environmental permits	9,588	
Assembled workforce	2,083	
Other intangibles	1,572	1,572
	72,702	39,360
Less accumulated amortization	(3,522)	(1,466)
	$ 69,180	$ 37,894

The following table sets forth future estimated amortization expense on amortizable intangible assets as follows (in thousands):

Years ending December 31,	
2006	$ 2,966
2007	2,747
2008	2,747
2009	2,723
2010	2,718
Thereafter	55,279
	$ 69,180

7. INVESTMENT IN FRONTIER

RPL owns a 22.22% partnership interest in Frontier which is accounted for by the equity method of accounting. The summarized balance sheets and income statements are presented below (unaudited):

Balance Sheets

	December 31,	
	2005	2004
	(in thousands)	
ASSETS		
Current assets	$ 2,644	$ 2,785
Property and equipment, net	10,411	9,110
	$ 13,055	$ 11,895
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities	$ 572	$ 1,257
Other liabilities	1,881	2,020
Partners' capital	10,602	8,618
	$ 13,055	$ 11,895

Statements of Income

	Year Ended December 31,		
	2005	2004	2003
	(in thousands)		
Revenue	$ 11,819	$ 11,268	$ 9,775
Operating expense	(3,702)	(4,270)	(3,644)
Depreciation expense	(377)	(368)	(364)
Operating income	7,740	6,630	5,767
Rate case and litigation expense			(7,295)
Other income (expense)	169	(14)	157

	Year Ended December 31,		
Net income (loss)	$ 7,909	$ 6,616	$ (1,371)

The unamortized portion of the excess cost over the Partnership's share of net assets of Frontier was $6.2 million and $6.3 million at December 31, 2005 and 2004, 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.

8. RELATED PARTY TRANSACTIONS

Sale of The *Anschutz* Corporation's Interest in the Partnership

On March 3, 2005, Anschutz sold all of its interest in Pacific Energy GP, Inc. to LBP, which was formed by LBMB in connection with the purchase. The acquisition by LBP (the "LB Acquisition") included the 100% ownership interest in Pacific Energy GP, Inc., 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 which represented a then 34.6% limited partner interest in the Partnership. 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 (the "General Partner"). Immediately following the consummation of the LB Acquisition, the General Partner distributed the 10,465,000 subordinated units of the Partnership to LBP.

In connection with the conversion of the Partnership's General Partner to a limited partnership, the 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" or the "Managing General Partner"), 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 the General Partner and the Partnership. All of the officers and employees of Pacific Energy GP, Inc. were transferred to fill the same positions with PEM, and the PEM Board established the same committees as had been maintained by Pacific Energy GP, Inc. prior to the LB Acquisition. PEM also adopted Pacific Energy GP, Inc.'s governance guidelines and its compensation structure and employee benefits plans and policies.

Additionally, on March 21, 2005, an affiliate of First Reserve Corporation ("First Reserve") acquired from LBMB a 30% partnership interest in LBP. LBMB and its affiliates continue to own a 70% partnership interest in LBP.

Lehman Brothers, Inc.

In connection with the purchase and associated financing of the Valero Acquisition including a private equity offering, public equity offering, senior notes offering and new credit facility, Lehman Brothers, Inc. and its affiliates provided advisory and underwriting services to the Partnership. Additionally, an affiliate of Lehman Brothers, Inc. was a participant in the syndicate that provided the Partnership's new senior secured credit facility. These agreements with Lehman Brothers, Inc. were reviewed and approved by the Conflicts Committee of the Board of Directors and the fees charged were customary for the types of services provided. For the period from March 3, 2005 through December 31, 2005, the Partnership incurred $9.9 million in fees with Lehman Brothers, Inc. and its affiliates, a portion of which was paid to non-affiliated financial institutions in the syndication of the New Credit Facility and in the public offering of equity.

Cost Reimbursements

Managing General Partner: The Partnership's Managing General Partner employs all U.S.-based employees. All employee expenses incurred by the Managing General Partner on behalf of the Partnership are charged back to the Partnership.

Special Agreement: On March 3, 2005, Douglas L. Polson, previously the Chairman of the Board of Directors of Pacific Energy GP, Inc., entered into a Special Agreement and a Consulting Agreement with PEM. In accordance with the Special Agreement, Mr. Polson resigned as Chairman of the Board of Directors of Pacific Energy GP, Inc. effective March 3, 2005. Mr. Polson was paid approximately $0.9 million, representing accrued salary through March 3, 2005, accrued but unused vacation and payment in satisfaction of other obligations under his employment agreement. The latter portion of this payment was recorded as an expense in "Transaction costs" in the accompanying condensed consolidated income statements (see "Note 17 Allocation of Net Income"). LBP reimbursed this amount, which was recorded as a partner's capital contribution. Pursuant to the Consulting Agreement, Mr. Polson has agreed to perform advisory services to PEM from time to time as shall be mutually agreed between Mr. Polson and the Chief Executive Officer of PEM. In consideration for Mr. Polson's services under the Consulting Agreement, which has a one-year term, Mr. Polson receives 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.

LBP and Anschutz: LBP and Anschutz reimbursed the Partnership for certain other costs relating to the LB Acquisition. These included $1.2 million for the Consent Solicitation (as defined and further described in "Note 9 Long-Term Debt", below) and $0.3 million for legal and other expenses (also see "Note 17 Allocation of Net Income").

Other Related Party Transactions

Related party balances at December 31, 2005 and 2004 were as follows:

	December 31,	
	2005	2004
	(in thousands)	
Amounts included in accounts receivable:		
Anschutz and affiliates	$	$ 224
Frontier Pipeline Company	142	257
	$ 142	$ 481
Amounts included in due to related parties:		
Due to Pacific Energy GP, Inc.	$	$ 533

Prior to March 3, 2005, in the ordinary course of its operations, the Partnership engaged in various transactions with Anschutz and its affiliates. These transactions, which are more thoroughly described below, are summarized in the following table for the years ended December 31, 2005, 2004 and 2003:

	Year Ended December 31,		
	2005	2004	2003
		(in thousands)	
Revenue:			
Anschutz and affiliates	$ 79	$ 528	$ 1,120
Frontier Pipeline Company	782	880	575
General and administrative expense:			
Anschutz and affiliates	129	316	169
Crude oil purchases:			
Frontier Pipeline Company	1,355		

Revenue from Related Parties

A subsidiary of Anschutz 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 Anschutz subsidiary and a third party, the performance of which required the Anschutz subsidiary to ship on

Line 2000, was assigned to the Partnership for consideration equal to the value of transferred inventory. The agreement ended April 1, 2003. In addition, a subsidiary of Anschutz 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 Anschutz 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 Anschutz 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 $0.8 million, $0.9 million and $0.6 million for the years ended December 31, 2005, 2004 and 2003, respectively.

Expenses Paid to Related Parties

Pursuant to an easement agreement between PPS and Union Pacific Corporation ("UPC"), UPC provides the Partnership with access to its right-of-way for a portion of Line 2000 in return for an annual rental. Philip F. Anschutz, a director of the Partnership's General Partner until March 3, 2005, and sole stockholder of Anschutz Company, the indirect parent until March 3, 2005, of the Partnership's General Partner, is a director of UPC.

From mid-2002 through December 31, 2005, the Partnership utilized a financial accounting system owned and provided by Anschutz under a shared services arrangement. In addition, the Partnership from time to time until mid-2003 utilized the services of Anschutz's risk management personnel for acquiring the Partnership's insurance, and the Partnership's surety bonds were, until 2004, issued under Anschutz's bonding line. From January 2003 through December 31, 2005, Anschutz charged the Partnership a fee of $0.1 million per year for these services and together with any out-of-pocket costs. The fixed annual fee included all license, maintenance and employee costs associated with our use of the financial accounting system.

In January 2003, the Partnership began leasing office space from an affiliate of Anschutz, for a term of five years at an initial annual cost of $0.1 million. The lease was terminated in February 2006.

9. LONG-TERM DEBT

The Partnership's long-term debt obligations are shown below:

	December 31,	
	2005	2004
	(in thousands)	
$400 million senior secured credit facility, bearing interest at 5.0% on December 31, 2005, due September 30, 2010	$ 140,751	$
Senior secured U.S. revolving credit facility, repaid and terminated on September 30, 2005		51,000
Senior secured Canadian revolving credit facility, repaid and terminated on September 30, 2005		54,005
$7^{1}/_{8}$% senior notes, due June 2014, net of unamortized discount of $3,882 and $4,202 and including fair value increases of $567 and $2,693, respectively	246,684	248,491
$6^{1}/_{4}$% senior notes, due September 2015, net of unamortized discount of $782	174,218	
Future payment for MAPL assets, net of unamortized discount of $309 and $480, respectively	3,979	3,667
Total	565,632	357,163
Less current portion		
Long-term debt	$ 565,632	$ 357,163

Principal payments due on long-term debt during each of the five years subsequent to December 31, 2005 are as follows (in thousands):

Year ending December 31,	
2006	$
2007	3,979
2008	
2009	
2010	140,751
Thereafter	420,902
Total	$ 565,632

$400 million Senior Secured Credit Facility

On September 30, 2005, the Partnership entered into a new five-year $400 million senior secured revolving credit facility (the "New Credit Facility") that replaced the Partnership's previous U.S. and Canadian revolving credit facilities. The New Credit Facility is available for general Partnership purposes in the U.S. and Canada, including working capital, letters of credit and distributions to unitholders (subject to certain limitations). The New Credit Facility matures on September 30, 2010, but the Partnership may prepay all loans under the New Credit Facility without premium or penalty. Obligations under the New Credit Facility are guaranteed by all of the subsidiaries of the Partnership except those for which regulatory approval is required and are secured by substantially all of the assets of the Partnership, excluding property held by the non-guaranteeing subsidiaries. The New Credit Facility is recourse to the Partnership and the guarantors, but non-recourse to the General Partner.

Subject to certain limited exceptions, indebtedness under the New 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 Bank of America, N.A. or the Federal Funds rate plus 0.50% (or in the case of borrowings under the Canadian sub-facility described below, Canadian US dollar base rate or Canadian prime rate) each plus an applicable margin ranging from 0% to 0.75% or (ii) the Eurodollar rate plus an applicable margin ranging from 0.75% to 2.00%. The applicable margins fluctuate based on the Partnership's credit rating at any given time. In addition, the Partnership incurs a commitment fee which ranges from 0.1875% to 0.5000% per annum on the unused portion of the New Credit Facility.

Included in the New Credit Facility is a Canadian sub-facility for Rangeland Pipeline Company ("RPC"), one of the Partnership's Canadian subsidiaries. The Canadian sub-facility currently has a limit of U.S.$100 million, but can be adjusted from time to time by the Partnership. The Canadian sub-facility includes an option for RPC to receive loans in either U.S. dollars or Canadian dollars.

The New Credit Facility contains certain financial covenants and covenants limiting the ability of the Partnership to, among other things, incur or guarantee indebtedness, change ownership or structure, including mergers, consolidations, liquidations and dissolutions, sell or transfer assets and properties, and enter into a new line of business. At December 31, 2005, the Partnership was in compliance with all such covenants.

The Partnership provides certain suppliers with irrevocable standby letters of credit to secure its obligation for the purchase of crude oil. These letters of credit are issued under the Partnership's credit facility, and the liabilities with respect to these purchase obligations are recorded in "Accrued crude oil purchases" on the Partnership's balance sheet in the month the crude oil is purchased. Generally, these letters of credit are issued for up to sixty-day periods and are terminated upon completion of each transaction. In addition, the Partnership provided a letter of credit to the seller of the MAPL pipeline to secure a note payable. At December 31, 2005 and 2004, The Partnership had outstanding letters of credit totaling approximately $14.8 million and $4.2 million, respectively.

As of December 31, 2005, in addition to $14.8 million of letters of credit, $140.8 million was outstanding under the New Credit Facility, including $55.8 million under the Canadian sub-facility, and there was $125.5 million of undrawn available credit.

The New Credit Facility was entered into with a syndicate of financial institutions, including an affiliate of Lehman Brothers, Inc., which is an affiliate of LBP (see "Note 8 Related Party Transactions").

7$^1/_8$% Senior Notes Due June 2014

On June 16, 2004, the Partnership and its 100% owned subsidiary, Pacific Energy Finance Corporation, completed the sale of $250 million of 7$^1/_8$% senior unsecured notes due June 15, 2014. The 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 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 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. 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 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 notes are jointly and severally guaranteed by certain of the Partnership's subsidiaries, namely Pacific Energy Group LLC, Pacific Marketing and Transportation LLC, Pacific Atlantic Terminals LLC, Rocky Mountain Pipeline System LLC, Ranch Pipeline LLC, PEG Canada GP LLC and PEG Canada, L.P.

The indenture governing the 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; or consolidate, merge or transfer all or substantially all of its assets. At December 31, 2005, the Partnership was in compliance with all such covenants.

Under the indenture governing the Partnership's $7^1/_8$% senior notes due 2014, the Partnership would have been required to make a "Change of Control Offer" to the holders of such notes if the LB Acquisition caused a rating decline by a credit rating agency. In order to avoid triggering the "Change of Control Offer" provision, the Partnership solicited the consent (the "Consent Solicitation") of the holders of the $7^1/_8$% notes to amend certain provisions of the Indenture, including an amendment to the definition of "Change of Control." The Consent Solicitation was completed on February 10, 2005 with a majority of the holders of the senior notes consenting 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. Fees of $0.6 million paid to holders of the notes were capitalized and included in "Other assets, net" in the accompanying condensed consolidated balance sheet at December 31, 2005 and are being amortized over the remaining life of the $7^1/_8$% notes. Other solicitation-related fees and expenses of approximately $0.6 million are included in "Transaction costs" in the accompanying condensed consolidated statements of income. LBP and Anschutz reimbursed the Partnership for the entire cost of the Consent Solicitation, which reimbursement is recorded as a general partner's capital contribution (see "Note 8 Related Party Transactions").

$6^1/_4$% Senior Notes Due 2015

On September 23, 2005, the Partnership and its 100% owned subsidiary, Pacific Energy Finance Corporation, completed the sale of $175 million of $6^1/_4$% senior unsecured notes due September 15, 2015. The notes were sold in a private offering to qualified institutional buyers in reliance on Rule 144A under the Securities Act of 1933 and to non-U.S. persons under Regulation S of the Securities Act of 1933. In January 2006, the 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 notes were sold for 99.544% of face value resulting in an effective interest rate of 6.3125% to maturity. Interest payments are due on March 15 and September 15 of each year, beginning on March 15, 2006.

The notes are jointly and severally guaranteed by the same Partnership subsidiaries that guarantee the $7^1/_8$% senior notes, due June 2014. At any time prior to September 15, 2008, the Partnership has the option to redeem up to 35% of the aggregate principal amount of notes at a redemption price of 106.25% of the principal amount with the net cash proceeds of one or more equity offerings. At any time prior to September 15, 2010, the Partnership may redeem some or all of the notes at a price equal to 100% of the principal amount, plus a make-whole premium and accrued and unpaid interest, if any, to the date of redemption. The Partnership will also have the option to redeem the notes, in whole or in part, at any time on or after September 15, 2010 at the following redemption prices:

Year	Percentage
2010	103.125%
2011	102.083
2012	101.042
2013 and thereafter	100.000

The indenture governing the 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; or consolidate, merge or transfer all or substantially all of its assets. At December 31, 2005, the Partnership was in compliance with all such covenants.

Net proceeds from the issuance of the notes were $170.9 million after deducting the $0.8 million discount and offering expenses of $3.3 million. The net proceeds were used to partially fund the Valero Acquisition.

Future Payment for MAPL Assets

In connection with the purchase of the MAPL pipeline, the Partnership is obligated to pay the seller Cdn$5.0 million (U.S.$4.3 million) on June 30, 2007. The future payment was discounted at 5%. The carrying value of the obligation was Cdn$4.4 million (U.S.$4.0 million) at December 31, 2005.

10. WRITE OFF OF DEFERRED FINANCING COSTS AND INTEREST RATE SWAP TERMINATION EXPENSE

On June 16, 2004, in connection with the repayment of a term loan, the Partnership had a $2.3 million non-cash write-off of deferred financing costs and incurred a $0.6 million cash expense to terminate related interest rate swaps.

11. INCOME TAXES

In May 2004, the Partnership acquired the Rangeland Pipeline system (see "Note 3 Acquisitions"). The Partnership's 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 it unitholders. However, the Partnership's Canadian subsidiaries are taxable entities in Canada and are subject to Canadian federal and provincial income taxes. In addition, intercompany interest payments and repatriation of funds through dividends are subject to withholding tax.

Components of the income tax expense for the years ended December 31, 2005 and 2004 are as follows:

	Year Ended December 31,	
	2005	2004
	(in thousands)	
Current tax expense:		
Canadian federal and provincial income tax	$ (6)	$ 114
Capital tax	263	212
Withholding taxes	745	
Other	250	
Total	1,252	326
Deferred tax expense (benefit):		
Canadian federal and provincial income tax	(144)	(535)
Withholding taxes	55	470
Total	(89)	(65)
Total tax expense	$ 1,163	$ 261

The difference between the statutory federal income tax rate and the Partnership's effective income tax rate is summarized as follows:

	Year Ended December 31,	
	2005	2004
	(in thousands)	
Earnings before income tax	$ 40,811	$ 35,990
Federal income tax rate	35%	35%
Income tax at statutory rate	$ 14,284	$ 12,597
Increase (decrease) as a result of:		
Partnership earnings not subject to tax	(14,418)	(13,051)
Canadian withholding and capital taxes	1,063	682
Other	234	33
Total tax expense	$ 1,163	$ 261

Deferred tax assets and liabilities result from the following:

	December 31, 2005	December 31, 2004
	(in thousands)	
Deferred tax assets:		
Book accruals in excess of current tax deductions	$ 1,198	$ 647
Net operating losses carried forward	2,941	2,312
Share and debt issue costs deductible in future years	15	21
Total deferred tax assets	4,154	2,980
Deferred tax liabilities:		
Canadian partnership income not currently taxable	3,092	1,926
Property, plant and equipment in excess of tax values	24,279	23,559
Intangible assets in excess of tax values	11,972	11,581
Withholding tax on future repatriation of income	582	470
Total deferred tax liabilities	39,925	37,536
Net deferred tax liabilities	$ 35,771	$ 34,556

The Partnership has $2.9 million of net operating loss carryforwards, of which $2.3 million will expire in the year 2014 and $0.6 million will expire in the year 2015. The Partnership believes it is more likely than not that the net operating loss carryforwards will be utilized prior to their expiration; therefore no valuation allowance is considered necessary.

12. ENVIRONMENTAL LIABILITIES

The Partnership is subject to numerous federal (U.S. and Canadian), state, provincial and local laws which regulate the discharge of materials into the environment or that otherwise relate to the protection of the environment. The following table presents the activity of the Partnership's environmental liabilities.

	December 31, 2005	December 31, 2004
	(in thousands)	
Balance at beginning of year	$ 8,657	$ 5,486
Liabilities assumed in acquisitions	9,675	3,275
Additions charged to expense	267	
Foreign currency translation adjustment	104	431
Expenditures	(371)	(535)
Balance at end of year	18,332	8,657
Less: current portion of environmental liabilities, included in "Other current liabilities"	(1,715)	(1,388)
Long-term portion of environmental liabilities	$ 16,617	$ 7,269

The actual future costs for environmental remediation activities will depend on, among other things, the identification of any additional sites, the determination of the extent of the contamination at each site, the timing and nature of required remedial actions, the technology available and required to meet the various existing legal requirements, the nature and extent of future environmental laws, inflation rates and the determination of the Partnership's liability at multi-party sites, if any, in light of uncertainties with respect to joint and several liability, and the number, participation levels and financial viability of other potentially responsible parties.

13. CONTINGENCIES

In August, 2005, Rangeland Pipeline Company ("RPC"), a wholly-owned subsidiary of the Partnership, learned that a Statement of Claim was filed by Desiree Meier and Robert Meier in the Alberta Court of Queen's Bench, Judicial District of Red Deer, naming RPC as defendant, and alleging personal injury and property damage caused by an alleged release of petroleum substances onto plaintiff's land by a prior owner and operator of the pipeline that is currently owned and operated by the Partnership. The claim seeks Cdn$1 million (approximately U.S.$0.9 million at December 31, 2005) in general damages, Cdn$2 million (approximately U.S.$1.7 million at December 31, 2005) in special damages, and, in addition, unspecified amounts for punitive, exemplary and aggravated damages, costs and interest. The Statement of Claim has not been served on RPC, so RPC has not been required to file an answer. RPC believes the claim is without merit, and intends to vigorously defend against it. RPC also believes that certain of the claims, if successfully proven by the plaintiffs, would be liabilities retained by the pipeline's prior owner under the terms of the agreement whereby the Partnership acquired the pipeline in question.

In connection with the Valero Acquisition, the Partnership assumed responsibility for the defense of a lawsuit filed in 2003 against Support Terminals Services, Inc., ("ST Services") by ExxonMobil Corporation ("ExxonMobil") in New Jersey state court. The Partnership has also assumed any liability that might be imposed on ST Services as a result of the suit. In the suit, ExxonMobil seeks reimbursement of approximately $400,000 for remediation costs it has incurred, from GATX Corporation, Kinder Morgan Liquid Terminals, the successor in interest to GATX Terminals Corporation, and ST Services. ExxonMobil also seeks a ruling imposing liability for any future remediation and related liabilities on the same defendants. These costs are associated with the Paulsboro, New Jersey terminal that was acquired by the Partnership on September 30, 2005. ExxonMobil claims that the costs and future remediation requirements are related to releases at the site subsequent to its sale of the terminal to GATX in 1990 and that, therefore, any remaining remediation requirements are the responsibility of GATX Corporation, Kinder Morgan and ST Services. The Partnership believes the claims against ST Services are without merit, and intend to vigorously defend against them.

The Partnership is involved in various other regulatory disputes, litigation and claims arising out of its operations in the normal course of business (see also "Note 4 Line 63 Oil Release Reserve"). The Partnership is not currently a party to any legal or regulatory proceedings the resolution of which could be expected to have a material adverse effect on its business, financial condition, liquidity or results of operations.

14. COMMITMENTS

Leases

The Partnership is obligated under several noncancelable operating leases, primarily for the rental of office space, trucks and equipment, which expire through the year 2011. These leases generally require the Partnership to pay all operating costs such as maintenance. Rental expense for all operating leases during the years ended December 31, 2005, 2004 and 2003 amounted to $1.9 million,

$1.5 million and $1.2 million, respectively. Future minimum rental payments under noncancelable operating leases at December 31, 2005 are as follows (in thousands):

Year ending December 31,		
2006	$	1,378
2007		1,041
2008		761
2009		402
2010		174
Thereafter		28
	$	3,784

Right-of-Way Obligations

The Partnership has secured various rights-of-way for the pipeline systems under right-of-way agreements that provide for annual payments to third parties. Right-of-way payments, which are included in operating expenses, totaled $3.3 million, $3.4 million and $2.9 million in 2005, 2004 and 2003, respectively.

The Partnership operates under various right-of-way and franchise agreements, certain of which expire at various times through at least 2035. Due to the nature of the Partnership's operations, the Partnership expects to continue making payments and renewing the right-of-way agreements. As of December 31, 2005, future minimum payments under the Partnership's right-of-way agreements of $4.0 million in 2006, between $4.5 million and $5.1 million annually in 2007 through 2010 and approximately $67.3 million thereafter reflect the Partnership's commitment for the next 15 years, assuming the current right-of-way agreements will be renewed during that period. The annual amounts payable under various right-of-way agreements are subject to adjustments as described above as well as for the effects of inflation, which is estimated at 5% per year.

15. PARTNERS' CAPITAL

Common Units Outstanding

There were 31,448,931 common units outstanding at December 31, 2005, with the public unitholders owning 28,832,681 units and LB Pacific, LP owning 2,616,250 units.

Subordinated Units and Conversion

All of the 7,848,750 subordinated units outstanding at December 31, 2005 were owned by LB Pacific, LP. The purpose of the subordinated units is to increase the likelihood that during the subordination period there will be available sufficient cash to pay the minimum quarterly distribution on the common units. The subordination period will generally expire on the first day of any quarter beginning after June 30, 2007 once certain financial tests are achieved. Prior to the end of the subordination period, 50% of the subordinated units (25% in respect of each quarter ending on or after June 30, 2005 and 2006) may convert into common units on a one-for-one basis. On August 12, 2005, pursuant to the terms of the Partnership's partnership agreement, 25% or 2,616,250 subordinated units were converted to common units on a one-for-one basis.

General Partner Interest

The Partnership's General Partner holds a 2% interest in the Partnership and is required to make additional capital contributions to the Partnership upon the issuance of any additional units, if necessary, to maintain its capital account balance equal to 2% of the total capital accounts of all partners.

Distributions

Within 45 days after the end of each quarter, the Partnership will distribute all of its available cash, if any, to unitholders of record on the applicable date and to its General Partner. Available cash is generally defined as all of the Partnership's cash and cash equivalents on hand at the end of each quarter less reserves established by the General Partner for future requirements. Cash distributions in each of the three years ended December 31, 2005 were as follows:

Year Ended December 31,	Common Units	Subordinated Units	General Partner Interest	Total
		(in thousands)		
2005	$ 45,458	$ 19,981	$ 1,336	$ 66,775
2004	34,981	20,407	1,130	56,518
2003	21,650	19,624	841	42,115

In January 2006, the Partnership declared a cash distribution of $0.555 per limited partner unit for the fourth quarter of 2005, which was paid in February 2006 to unitholders of record as of January 31, 2006.

The General Partner is entitled to incentive distributions in quarters when the limited partner distribution exceeds $0.5125 per unit. The February 2006 distribution was the first quarterly distribution to exceed $0.5125 per limited partner unit and, accordingly, the General Partner received an incentive distribution of approximately $255,000 in addition to its 2% interest distribution.

Public Equity Offerings

During the three years ended December 31, 2005, the Partnership completed the following public equity offerings of its common units:

Period	Units	Gross Unit Price	Proceeds from Sale	General Partner Contribution	Costs	Net Proceeds
			(in thousands, except units and per unit amounts)			
September 2005	5,232,500	$ 32.00	$ 167,440	$ 3,417	$ 7,619	$ 163,238
March/April 2004	4,625,000	28.50	131,813	2,690	5,932	128,571
August/September 2003	5,612,000	24.66	138,392	1,955	6,676	133,671

Net proceeds from the September 2005 offering were used to partially fund the Valero Acquisition. Net proceeds from the March/April 2004 offering were used to partially fund the Rangeland acquisition and to repay borrowings under the U.S. revolving credit facility. Proceeds from the 2003 offering were used to repay indebtedness outstanding under PEG's revolving credit facility, which had been incurred in connection with the acquisition of PT storage and distribution system assets and to redeem 1,727,100 common units owned by the General Partner.

Private Equity Placement

On September 30, 2005, the Partnership sold 4,300,000 common units pursuant to a Common Unit Purchase Agreement with certain institutional investors at a price of $30.75 per unit. The Partnership received net proceeds of $131.8 million from the sale of the common units including the General Partner's contribution of $2.7 million, which were used to partially fund the Valero Acquisition.

Shelf Registration Statements

On December 23, 2005, the Partnership and certain subsidiaries 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 $1.0 billion of common units of the Partnership and debt securities of both the Partnership and certain subsidiaries. The SEC declared the registration statement effective on January 12, 2006. In addition, we have $110 million available and remaining under our August 2003 universal shelf registration statement.

16. DERIVATIVE FINANCIAL INSTRUMENTS

The Partnership uses derivative financial instruments primarily to reduce its exposure to adverse fluctuations in commodity prices, interest rates and foreign exchange rates. The Partnership formally designates and documents such financial instrument as a hedge of a specific underlying exposure, as well as the risk management objectives and strategies for undertaking the hedge transactions. The Partnership formally assesses, both at the inception and at least quarterly thereafter, whether the financial instruments that are used in hedging transactions are effective at offsetting changes in either the fair value or cash flows of the related underlying exposure. All of the Partnership's derivatives are commonly used over-the-counter instruments with liquid markets or are traded on the New York Mercantile Exchange. The Partnership does not enter into derivative financial instruments for trading or speculative purposes.

Commodity Price Risk Hedging

The Partnership uses derivative instruments (principally futures and options) to hedge its exposure to market price volatility related to its inventory or future sales of crude oil. Derivatives used to hedge market price volatility related to inventory are generally designated as fair value hedges, and derivatives related to future sale of crude oil are generally classified as cash flow hedges. Derivative instruments are included in other assets in the accompanying consolidated balance sheets.

Changes in the fair value of the Partnership's derivative instruments related to crude oil inventory are recognized in net income. For the years ended December 31, 2005, 2004 and 2003, "crude oil sales, net of purchases" were net of $0.8 million, $2.7 million and $0.3 million in losses, respectively, reflecting changes in the fair value of derivative instruments held as hedges related to crude oil marketing activities. Losses on derivatives were generally offset by gains in physical crude oil inventory positions. Changes in the fair value of the Partnership's derivative instruments related to the future sale of crude oil, which are generally for one year or less, are deferred and reflected in "accumulated other comprehensive income," a component of partners' capital, until the related revenue is reflected in the consolidated statements of income. As of December 31, 2005, a $0.1 million loss relating to the change in the fair value of highly effective derivative instruments was included in "accumulated other comprehensive income" and is expected to be reclassified to earnings in 2006. Since these amounts are based on market prices at the current period end, actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions. There were immaterial amounts of ineffectiveness associated with crude oil hedging in 2005, 2004 and 2003, respectively.

Interest Rate Risk Hedging

In connection with the issuance of its $7^1/_8$% senior notes due 2014, the Partnership 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 in June 2014 and are callable at the same dates and terms as the $7^1/_8$% senior notes. The Partnership 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, 2005, the Partnership recorded an increase of $0.6 million in the fair value of interest rate swaps. During the year ended December 31, 2005, the Partnership recognized reductions in interest expense of $1.3 million related to the difference between the fixed rate and the floating rate of interest on the interest rate swaps. As of December 31, 2005 and 2004, the Partnership had immaterial amounts of hedge ineffectiveness relating to these interest rate swaps.

In the third quarter of 2002, the Partnership entered into interest rate swap agreements that were to mature in 2007 and 2009 with a notional amount of $170.0 million. The Partnership designated these swaps as a hedge of its exposure to variability in future cash flows attributable to the LIBOR interest payments due on $170.0 million outstanding under a term loan facility. The average swap rate on this $170.0 million of debt was approximately 4.25%, resulting in an all-in interest rate on the $170.0 million of debt of approximately 6.50%. In June 2004, in conjunction with the issuance of the $7^1/_8$% Senior Notes and the repayment of the term loan, the Partnership bought back the swaps for a loss of $0.6 million.

Currency Exchange Rate Risk Hedging

The purpose of the Partnership's foreign currency hedging activities is to reduce the risk that the Partnership's cash inflows resulting from interest payments from its Canadian subsidiaries on intercompany debt will be adversely affected by changes in the U.S./Canadian exchange rate.

The Partnership entered into forward exchange contracts to hedge receipt of forecasted interest payments denominated in Canadian dollars. The effective portion of the change in fair value of these contracts, which have been designated as a cash flow hedge, is reported in "Accumulated other comprehensive income" and will be reclassified into earnings in "Other income" in the period the hedged transaction affects earnings. The ineffective portion, if any, of the change in fair value of this instrument will be immediately recognized in earnings. These foreign exchange contracts are as follows:

	Canadian dollars	US dollars	Average Exchange Rate
	(in thousands)		
2006	$ 7,200	$ 6,126	Cdn $1.18 to U.S. $1.00
2007	6,600	5,662	Cdn $1.17 to U.S. $1.00
2008	3,193	2,754	Cdn $1.16 to U.S. $1.00

As of December 31, 2005, a $0.2 million loss relating to foreign exchange contracts was deferred and included in "accumulated other comprehensive income" and is expected to be reclassified into earnings in 2006. For the year ended December 31, 2005, no gains or losses were recognized in the income statement for these foreign exchange contracts.

Credit Risks

By using derivative financial instruments to hedge exposures related to changes in commodity prices, interest rates and currency exchange rates, the Partnership exposes itself to market risk and credit risk. Market risk is the risk of loss arising from the adverse effect on the value of a financial instrument that results from changes in commodity prices, interest rates or currency exchange rates. The market risk associated with price volatility is managed by established parameters that limit the types and degree of market risk that may be undertaken.

Credit risk is the risk of loss arising from the failure of the derivative agreement counterparty to perform under the terms of the derivative agreement. When the fair value of a derivative agreement is positive, the counterparty is liable to the Partnership, which creates credit risk for the Partnership. When the fair value of a derivative agreement is negative, the Partnership is liable to the counterparty and, therefore, it creates credit risk for the counterparty. The counterparties the Partnership transacts with are large, well known companies in the industry or large creditworthy financial institutions. As such, the Partnership believes its exposure to counterparty credit risk is low. Nonetheless, there can be no assurance as to the performance of a counterparty.

Fair Value of Financial Instruments

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

	December 31,			
	2005		2004	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(in thousands)			
Crude oil hedging futures	$ 161	$ 161	$ 400	$ 400
Fair value interest rate swaps	567	567	2,693	2,693
Foreign exchange contracts	195	195		
Long-term debt	565,632	576,015	357,163	373,265

As of December 31, 2005 and 2004, 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 rates on the $7^1/_8$% senior notes due 2014 and the $6^1/_4$% senior notes due 2015 are fixed and the fair value is determined from a broker's price quote at December 31, 2005.

The carrying amount of derivative financial instruments represents 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 and foreign exchange contracts fair values are based on the prevailing market price at which the positions could be liquidated.

17. ALLOCATION OF NET INCOME

The allocation of net income between the Partnership's General Partner and limited partners is as follows.

	Year Ended December 31,		
	2005	2004	2003
		(in thousands)	
Net income	$ 39,648	$ 35,729	$ 25,029
Transaction costs reimbursed by general partner:			
$7^{1}/_{8}$% senior notes consent solicitation and other costs	893		
Severance and other costs	914		
Total transaction costs reimbursed by general partner	1,807		
Income before transaction costs reimbursed by general partner	41,455	35,729	25,029
General partner's share of income	2%	2%	2%
General partner allocated share of net income before transaction costs	829	715	501
Transaction costs reimbursed by general partner	(1,807)		
Net income (loss) allocated to general partner	$ (978)	$ 715	$ 501
Income before transaction costs reimbursed by general partner	$ 41,455	$ 35,729	$ 25,029
Limited partners share of income	98%	98%	98%
Limited partners share of net income	$ 40,626	$ 35,014	$ 24,528
Net income (loss) allocated to general partner	$ (978)	$ 715	$ 501
Net income allocated to limited partners	40,626	35,014	24,528
Net income	$ 39,648	$ 35,729	$ 25,029

LBP and Anschutz reimbursed the Partnership for certain costs incurred in connection with the LB Acquisition. The Partnership was reimbursed $1.2 million for costs incurred in connection with the Consent Solicitation, $0.3 million of legal and other costs and $0.9 million relating to severance costs (see "Note 8 Related Party Transactions"), for a total of $2.4 million. Of the $1.2 million incurred for the consent solicitation, $0.6 million was capitalized as deferred financing costs (and did not affect the income allocation) and $0.6 million was expensed.

18. LONG-TERM INCENTIVE PLAN

In 2002, the General Partner adopted the Long-Term Incentive Plan (the "Plan") for employees and affiliates who perform services for the Partnership. The Plan consists of two components, a restricted unit plan and a unit option plan. The Plan was amended in 2006. The Plan currently permits the granting of an aggregate of 1,750,000 restricted units and unit options and is administered by the Compensation Committee of the Managing General Partner, subject to approval by the Managing General Partner's Board of Directors. The Managing General Partner's Board of Directors in its discretion may terminate the Plan at any time with respect to any restricted units for which a grant has not yet been made. The Managing General Partner's Board of Directors also reserves the right to alter or amend the Plan from time to time, including increasing the number of common units with respect to which awards may be granted; provided, however, that no change in any outstanding grant may be made which would materially impair the rights of the participant without the consent of such participant. As the restricted units vest, the Managing General Partner has the option to acquire common units in the open market for delivery to the recipient or distribute newly issued common units from the Partnership. In all cases, the Managing General Partner is reimbursed by the Partnership for such expenditures.

Restricted unit activity during the years ended December 31, 2005, 2004 and 2003 was as follows:

	Number of Restricted Units
Balance at December 31, 2002	381,250
Granted	34,000
Vested(1)	(130,750)
Forfeited	(12,500)
Balance at December 31, 2003	272,000
Granted	11,500
Vested(1)	(135,750)
Forfeited	(3,000)
Balance at December 31, 2004	144,750
Vested(1)	(144,750)
Balance at December 31, 2005	

(1) Includes units relinquished in satisfaction of withholding taxes.

The Partnership recognized $0.2 million, $2.1 million and $3.2 million of compensation expense associated with these grants in 2005, 2004 and 2003.

On March 3, 2005, in connection with the LB Acquisition and the change in control of the Partnership's General Partner, all restricted units outstanding under the Partnership's Long-Term Incentive Plan immediately vested pursuant to the terms of the grants. The Partnership issued 99,583 common units and recognized a compensation expense of $3.1 million, which is included in "Accelerated long-term incentive plan compensation expense" in the accompanying condensed consolidated statements of income.

In addition, Canadian employees of the Partnership participate in a separate Phantom Unit Plan, which upon vesting provides for payment in cash for the equivalent of the Partnership's unit on the vesting date. In 2004, the General partner granted 15,000 phantom units to certain key employees which were to vest over five years from the date of grant. These phantom units also became immediately vested with the change in control of the Partnership's General Partner.

In December 2002, the General Partner granted 50,000 common unit options with a 10-year term. The unit options were granted with an exercise price of $19.50 per unit, which was equal to the fair market value at the date of grant and vested in 2003 and 2004. On July 8, 2005, these options were exercised, 8,149 common units were withheld to cover withholding taxes and the Partnership issued 41,851 new common units.

The Partnership applied APB Opinion No. 25, "Accounting for Stock Issued to Employees," and, accordingly, no compensation expense was recognized for its unit options in the financial statements.

In January 2006, the General Partner awarded restricted units to key employees that vest over a three-year period, beginning on March 1, 2006, and that are also subject to meeting annual financial performance objectives. The financial measure used is the Partnership's distributable cash flow per unit, as determined by the Compensation Committee, for the calendar year preceding each of the three annual vesting dates. The number of units to be delivered in any year, if any, will be a portion of the number vested on March 1 of that year based on accomplishment of performance targets for the previous calendar year. The Partnership will apply the accounting treatment under FAS 123R to these restricted units awards beginning on January 1, 2006.

19. EMPLOYEE BENEFIT PLANS

The General Partner sponsors a defined contribution 401(k) plan for its U.S. based employees whereby eligible employees may contribute up to 18% of their annual compensation to the plan, subject to certain defined limits. The General Partner matches employee contributions up to 6% to 12%, depending on years of service, of the employee's annual compensation. Total employer contributions to the plan were $1.0 million, $0.9 million and $1.0 million, for 2005, 2004 and 2003 respectively.

The Partnership's Canadian subsidiaries sponsor an employee savings plan (the "Savings Plan") and a defined contribution plan. Under the Savings Plan eligible employees may contribute a percentage of their salary to the Savings Plan. The Partnership's Canadian subsidiaries provide matching contributions between 1% and 6% depending on years of service. The defined contribution plan requires the Canadian subsidiaries to make a contribution to a tax-deferred account established in an employee's name. Employee contributions to the defined contribution plan are not required nor permitted. The Canadian subsidiaries make contributions of between 2% and 6% of an employee's annual compensation depending on years of service. Contributions are limited by the Canada Customs and Revenue Agency to Cdn$18,000 in 2006 for any employee. Total employer contributions to the plan for 2005 and 2004 were Cdn$0.4 million and Cdn$0.2 million.

20. SEGMENT INFORMATION

The Partnership's business and operations are organized into two business segments: the West Coast Business Unit and the Rocky Mountain Business Unit. The West Coast Business Unit includes: (i) Pacific Pipeline System LLC, owner of Line 2000 and Line 63, (ii) Pacific Marketing and Transportation LLC, owner of the PMT gathering system, (iii) Pacific Terminals LLC, owner of the Pacific Terminals storage and distribution system, which was acquired on July 31, 2003, and (iv) Pacific Atlantic Terminals LLC, which was formed for the purpose of holding the California and East Coast terminal assets the Partnership acquired in the Valero Acquisition on September 30, 2005. The Rocky Mountain Business Unit includes: (i) Rocky Mountain Pipeline System LLC, owner of the Partnership's interest in various pipelines that make up the Western Corridor and Salt Lake City Core systems and the Rocky Mountain Products Pipeline, which was acquired in the Valero Acquisition on September 30, 2005, (ii) Ranch Pipeline LLC, the owner of a 22.22% partnership interest in Frontier Pipeline Company, and (iii) PEG Canada, L.P. and its Canadian subsidiaries, which own and operate the Rangeland system (which was acquired on May 11, 2004). General and administrative costs, which consist of executive management, accounting and finance, human resources, information technology, investor relations, legal, and business development, are not allocated to the individual business units. Information regarding these two business units is summarized below:

	West Coast Operations	Rocky Mountain Operations	Intersegment and Intrasegment Eliminations	Total
		(in thousands)		
Year ended December 31, 2005				
Revenues:				
Pipeline transportation revenue	$ 63,006	$ 60,071	$ (6,429)	$ 116,648
Storage and terminaling revenue(1)	52,136		(150)	51,986
Pipeline buy/sell transportation revenue(2)		35,671		35,671
Crude oil sales, net of purchases(3)	19,809	374	(186)	19,997
Net revenue	134,951	96,116		224,302
Expenses:				
Operating	66,237	44,925	(6,765)	104,397
Line 63 oil release costs(4)	2,000			2,000
Depreciation and amortization	15,927	13,479		29,406
Total expenses	84,164	58,404		135,803
Share of net income of Frontier		1,757		1,757
Write-down of idle property	(450)			(450)
Operating income from segments(5)	$ 50,337	$ 39,469		$ 89,806
Identifiable assets(6)	$ 878,101	$ 549,244		$ 1,427,345
Capital expenditures(7)	$ 16,451	$ 26,571		$ 43,022
Year ended December 31, 2004				
Revenues:				
Pipeline transportation revenue	$ 67,173	$ 47,131	$ (5,909)	$ 108,395
Storage and terminaling revenue(1)	38,080		(503)	37,577
Pipeline buy/sell transportation revenue(2)		18,640		18,640
Crude oil sales, net of purchases(3)	16,907		(120)	16,787
Net revenue	122,160	65,771		181,399
Expenses:				
Operating	58,197	33,621	(6,532)	85,286
Depreciation and amortization	14,424	9,749		24,173
Total expenses	72,621	43,370		109,459
Share of net income of Frontier		1,328		1,328
Write-down of idle property	(800)			(800)
Operating income from segment(5)	$ 48,739	$ 23,729		$ 72,468
Identifiable assets(6)	$ 496,324	$ 341,706		$ 838,030
Capital expenditures(7)	$ 4,220	$ 6,949		$ 11,169

Year ended December 31, 2003				
Revenues:				
Pipeline transportation revenue	$ 67,946	$ 41,298	$ (7,433)	$ 101,811
Storage and terminaling revenue(1)	12,711			12,711
Crude oil sales, net of purchases(3)	21,293			21,293
Net revenue	101,950	41,298		135,815
Expenses:				
Operating	46,287	22,192	$ (7,433)	61,046
Depreciation and amortization	12,999	5,866		18,865
Total expenses	59,286	28,058		79,911
Share of net income of Frontier		(162)		(162)
Operating income from segment(5)	$ 42,664	$ 13,078		$ 55,742
Identifiable assets(6)	$ 509,137	$ 121,892		$ 631,029
Capital expenditures(7)	$ 4,023	$ 1,418		$ 5,441

(1) Includes the revenue of Pacific Terminals storage and distribution system, which Pacific Terminals acquired on July 31, 2003.

(2) Includes the revenue of the Rangeland system, which was acquired on May 11, 2004 and June 30, 2004.

(3) The above amounts are net of purchases of $623,115, $402,283 and $358,454 for 2005, 2004 and 2003, respectively.

(4) See "Note 4 Line 63 Oil Release Reserve" for further information.

(5) The following is a reconciliation of operating income as stated above to the statements of income:

	2005	2004	2003
		(in thousands)	
Operating income from above:			
West Coast Operations	$ 50,337	$ 48,739	$ 42,664
Rocky Mountain Operations	39,469	23,729	13,078
Operating income from segments	89,806	72,468	55,742
Less: General and administrative expense	18,472	15,400	13,705
Less: Accelerated long-term incentive plan compensation expense	3,115		
Less: Transaction costs	1,807		
Operating income	66,412	57,068	42,037
Interest and other income	1,119	1,032	479
Interest expense	(26,720)	(19,209)	(17,487)
		(2,901)	

	2005	2004	2003
Write-off of deferred financing cost and interest rate swap termination expense			
Income tax expense	(1,163)	(261)	
Net income	$ 39,648	$ 35,729	$ 25,029

(6) Identifiable segment assets do not include assets related to the Partnership's corporate activity. As of December 31, 2005, 2004 and 2003, corporate related assets were $49,107, $31,875 and $19,174, respectively.

(7) Capital expenditures do not include the Pier 400 project and other parent-level related capital expenditures. Pier 400 project and other parent-level related capital expenditures were $8,695, $5,351, and $5,451 as of December 31, 2005, 2004, and 2003, respectively.

Geographic Data

Set forth below are revenues and identifiable assets attributable to the United States and Canada for the years ended December 31, 2005 and 2004:

	Year Ended December 31,	
	2005	2004
	(in thousands)	
Revenues:		
United States	$ 188,631	$ 162,759
Canada	35,671	18,640
	$ 224,302	$ 181,399

	December 31,	
	2005	2004
	(in thousands)	
Total Assets:		
United States	$ 1,221,246	$ 658,594
Canada	255,206	211,311
	$ 1,476,452	$ 869,905

21. SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

Certain of the Partnership's 100% owned subsidiaries have issued full, unconditional, and joint and several guarantees of the $7^1/_8$% senior notes due 2014 and the $6^1/_4$% senior notes due 2015 (the "Senior Notes"). Given that certain, but not all subsidiaries of the Partnership are guarantors of its Senior Notes, the Partnership is required to present the following supplemental condensed consolidating financial information. For purposes of the following footnote, the Partnership is referred to as "Parent", while the "Guarantor Subsidiaries" are Rocky Mountain Pipeline System LLC, Pacific Marketing and Transportation LLC, Pacific Atlantic Terminals LLC, Ranch Pipeline LLC, PEG Canada GP LLC, PEG Canada, L.P. and Pacific Energy Group LLC, and "Non-Guarantor Subsidiaries" are Pacific Pipeline System LLC, Pacific Terminals LLC, Rangeland Pipeline Company, Rangeland Marketing Company, Rangeland Northern Pipeline Company, Rangeland Pipeline Partnership and Aurora Pipeline Company, Ltd.

The following supplemental condensed consolidating financial information reflects the Parent's separate accounts, the combined accounts of the Guarantor Subsidiaries, the combined accounts of the Parent's Non-Guarantor Subsidiaries, the combined consolidating adjustments and eliminations and the Parent's consolidated accounts for the dates and periods indicated. For purposes of the following condensed consolidating information, the Parent's investments in its subsidiaries and the Guarantor Subsidiaries' investments in their subsidiaries are accounted for under the equity method of accounting:

Balance Sheet December 31, 2005

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands)				
Assets:					
Current assets	$ 104,989	$ 139,457	$ 81,846	$ (134,177)	$ 192,115
Property and equipment		583,330	602,204		1,185,534
Equity investments	429,802	197,239		(618,885)	8,156
Intangible assets		31,220	37,960		69,180
Intercompany notes receivable	661,313	340,905		(1,002,218)	
Other assets	13,426		8,041		21,467
Total assets	$ 1,209,530	$ 1,292,151	$ 730,051	$ (1,755,280)	$ 1,476,452
Liabilities and partners' capital:					
Current liabilities	$ 5,389	$ 191,516	$ 93,459	$ (134,177)	$ 156,187
Long-term debt	505,902		59,730		565,632
Deferred income taxes		582	35,189		35,771
Intercompany notes payable		661,313	340,905	(1,002,218)	
Other liabilities		8,938	11,685		20,623
Total partners' capital	698,239	429,802	189,083	(618,885)	698,239
Total liabilities and partners' capital	$ 1,209,530	$ 1,292,151	$ 730,051	$ (1,755,280)	$ 1,476,452

Balance Sheet December 31, 2004

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands)				
Assets:					
Current assets	$ 14,869	$ 80,320	$ 41,948	$ (41,592)	$ 95,545
Property and equipment		129,496	589,128		718,624
Equity investments	366,148	194,787		(553,049)	7,886
Intangible assets		118	37,776		37,894
Intercompany notes receivable	283,550	338,884		(622,434)	
Other assets	7,223	1,875	858		9,956
Total assets	$ 671,790	$ 745,480	$ 669,710	$ (1,217,075)	$ 869,905
Liabilities and partners' capital:					
Current liabilities	$ 833	$ 44,177	$ 44,627	$ (41,592)	$ 48,045
Long-term debt	248,491	51,000	57,672		357,163
Deferred income taxes		470	34,086		34,556

Balance Sheet
December 31, 2004

Intercompany notes payable		283,550	338,884	(622,434)	
Other liabilities		135	7,540		7,675
Total partners' capital	422,466	366,148	186,901	(553,049)	422,466
Total liabilities and partners' capital	$ 671,790	$ 745,480	$ 669,710	$ (1,217,075)	$ 869,905

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Statement of Income
Year Ended December 31, 2005

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
			(in thousands)		
Net operating revenues before expenses	$	$ 89,968	$ 141,099	$ (6,765)	$ 224,302
Operating expenses		(48,421)	(62,741)	6,765	(104,397)
Line 63 oil release costs			(2,000)		(2,000)
General and administrative expense(1)		(16,317)	(2,155)		(18,472)
Accelerated long-term incentive plan compensation expense		(2,675)	(440)		(3,115)
Transaction costs	(893)	(914)			(1,807)
Depreciation and amortization expense		(9,558)	(19,848)		(29,406)
Write-down of idle property			(450)		(450)
Share of net income of Frontier		1,757			1,757
Operating income	(893)	13,840	53,465		66,412
Interest expense	(21,191)	(2,418)	(3,111)		(26,720)
Intercompany interest income (expense)		25,910	(25,910)		
Equity earnings	61,455	24,050		(85,505)	
Interest and other income (expense)	277	1,123	(281)		1,119
Income tax benefit (expense)		(1,050)	(113)		(1,163)
Net income	$ 39,648	$ 61,455	$ 24,050	$ (85,505)	$ 39,648

Statement of Income
Year Ended December 31, 2004

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
			(in thousands)		
Net operating revenues before expenses	$	$ 64,038	$ 123,893	$ (6,532)	$ 181,399
Operating expenses		(40,257)	(51,561)	6,532	(85,286)
General and administrative expense(1)		(14,139)	(1,261)		(15,400)
Depreciation and amortization expense		(6,660)	(17,513)		(24,173)
Write-down of idle property			(800)		(800)
Share of net income of Frontier		1,328			1,328
Operating income		4,310	52,758		57,068
Interest expense	(8,752)	(8,493)	(1,964)		(19,209)
Write-off of deferred financing cost and interest rate swap termination expense		(2,901)			(2,901)
Intercompany interest income (expense)		20,429	(20,429)		
Equity earnings	44,464	30,773		(75,237)	
Interest and other income	17	816	199		1,032
Income tax benefit (expense)		(470)	209		(261)
Net income	$ 35,729	$ 44,464	$ 30,773	$ (75,237)	$ 35,729

(1)

General and administrative expense is not currently allocated between Guarantor and Non-Guarantor Subsidiaries for financial reporting purposes.

Statement of Income
Year Ended December 31, 2003

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating adjustments	Total
			(in thousands)		
Net operating revenues before expenses	$	$ 62,589	$ 80,659	$ (7,433)	$ 135,815
Operating expenses		(38,663)	(29,816)	7,433	(61,046)
General and administrative expense(1)		(13,582)	(123)		(13,705)
Depreciation and amortization expense		(6,336)	(12,529)		(18,865)
Share of loss of Frontier		(162)			(162)
Operating income		3,846	38,191		42,037
Interest expense		(17,487)			(17,487)
Intercompany interest income (expense)		10,322	(10,322)		
Equity earnings	25,010	27,907		(52,917)	
Interest and other income	19	422	38		479
Net income	$ 25,029	$ 25,010	$ 27,907	$ (52,917)	$ 25,029

(1) General and administrative expense is not currently allocated between Guarantor and Non-Guarantor Subsidiaries for financial reporting purposes.

Statement of Cash Flows
Year Ended December 31, 2005

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
			(in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net income	$ 39,648	$ 61,455	$ 24,050	$ (85,505)	$ 39,648
Adjustments to reconcile net income to net cash provided by operating activities:					
Equity earnings	(61,455)	(24,050)		85,505	
Distributions from subsidiaries	66,775	38,643		(105,418)	
Depreciation, amortization and other	1,025	12,576	20,859		34,460
Net changes in operating assets and liabilities	4,555	(5,024)	7,255	(4,786)	2,000
NET CASH PROVIDED BY OPERATING ACTIVITIES	50,548	83,600	52,164	(110,204)	76,108
CASH FLOWS FROM INVESTING ACTIVITIES:					
Acquisitions		(462,553)			(462,553)
Additions to property, equipment and other		(18,565)	(31,633)		(50,198)
Intercompany	(465,466)			465,466	
NET CASH USED IN INVESTING ACTIVITIES	(465,466)	(481,118)	(31,633)	465,466	(512,751)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	416,397	392,479	(22,334)	(355,262)	431,280
Effect of translation adjustment			44		44
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	1,479	(5,039)	(1,759)		(5,319)
CASH AND CASH EQUIVALENTS, beginning of year	2,713	17,523	3,147		23,383
CASH AND CASH EQUIVALENTS, end of year	$ 4,192	$ 12,484	$ 1,388	$	$ 18,064

Statement of Cash Flows
Year Ended December 31, 2004

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
			(in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net income	$ 35,729	$ 44,464	$ 30,773	$ (75,237)	$ 35,729
Adjustments to reconcile net income to net cash provided by operating activities:					
Equity earnings	(44,464)	(30,773)		75,237	
Distributions from subsidiaries	56,518	47,519		(104,037)	
Depreciation, amortization and other	336	11,086	18,048		29,470
Net changes in operating assets and liabilities	760	(9,271)	(6,439)	6,977	(7,973)
NET CASH PROVIDED BY OPERATING ACTIVITIES	48,879	63,025	42,382	(97,060)	57,226
CASH FLOWS FROM INVESTING ACTIVITIES					
Acquisitions			(138,701)		(138,701)
Additions to property, equipment and other		(10,600)	(6,651)		(17,251)
Intercompany	(369,533)	(97,602)		467,135	
NET CASH USED IN INVESTING ACTIVITIES	(369,533)	(108,202)	(145,352)	467,135	(155,952)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	322,621	55,316	105,767	(371,294)	112,410
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	1,967	8,920	2,797		13,684
CASH AND CASH EQUIVALENTS, beginning of year	746	8,603	350		9,699
CASH AND CASH EQUIVALENTS, end of year	$ 2,713	$ 17,523	$ 3,147	$	$ 23,383

Statement of Cash Flows
Year Ended December 31, 2003

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
			(in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net income	$ 25,029	$ 25,010	$ 27,907	$ (52,917)	$ 25,029
Adjustments to reconcile net income to net cash provided by operating activities:					
Equity earnings	(25,010)	(27,907)		52,917	
Distributions from subsidiaries	42,115	39,613		(81,728)	
Depreciation, amortization and other		12,514	12,529		25,043
Net changes in operating assets and liabilities	42	(47)	(8,102)	758	(7,349)
NET CASH PROVIDED BY OPERATING ACTIVITIES	42,176	49,183	32,334	(80,970)	42,723
CASH FLOWS FROM INVESTING ACTIVITIES					
Acquisitions			(169,740)		(169,740)
Additions to property, equipment and other		(6,752)	(3,840)		(10,592)
Intercompany	(90,000)	(167,000)		257,000	
NET CASH USED IN INVESTING ACTIVITIES	(90,000)	(173,752)	(173,580)	257,000	(180,332)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	46,207	120,921	133,402	(177,095)	123,435
NET DECREASE IN CASH AND CASH EQUIVALENTS	(1,648)	(4,682)	(7,844)		(14,174)
CASH AND CASH EQUIVALENTS, beginning of year	2,394	13,285	8,194		23,873
CASH AND CASH EQUIVALENTS, end of year	$ 746	$ 8,603	$ 350	$	$ 9,699

22. QUARTERLY FINANCIAL DATA (unaudited)

Year ended December 31, 2005

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
			(in thousands, except per unit amounts)		
Net revenue	$ 49,247	$ 52,775	$ 54,520	$ 67,760	$ 224,302
Operating income	9,227	17,667	19,342	20,176	66,412
Net income	3,421	12,220	12,166	11,841	39,648
Basic net income per limited partner unit	0.17	0.40	0.39	0.30	1.25
Diluted net income per limited partner unit	0.17	0.40	0.39	0.30	1.25

	Year ended December 31, 2004				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(in thousands, except per unit amounts)				
Net revenue	$ 39,662	$ 45,997	$ 48,091	$ 47,649	$ 181,399
Operating income	12,042	16,172	15,126	13,728	57,068
Net income	8,077	9,128	9,890	8,634	35,729
Basic net income per limited partner unit	0.32	0.30	0.33	0.29	1.23
Diluted net income per limited partner unit	0.31	0.30	0.33	0.29	1.23