UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D. C. 20549

FORM 10-K

(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, 2002**

or

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

31345
(Commission File Number)

PACIFIC ENERGY PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

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

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

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

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

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

Title of Each Class

None

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

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

Indicate by check mark whether the registrant is an accelerated filer. Yes o No ý

The aggregate market value of the voting stock held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter is not applicable. Pacific Energy Partners, L.P. was a privately held partnership prior to July 26, 2002, and therefore had no voting stock held by non-affiliates.

There were 10,465,000 of the registrant's Common Units and 10,465,000 of the registrant's Subordinated Units outstanding as of February 28, 2003.

Documents incorporated by reference: None.

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

Glossary of Terms

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

ANS	Alaskan North Slope
Anschutz	The Anschutz Corporation
ARCO	ARCO Pipe Line Company
AREPI	Anschutz Ranch East Pipeline LLC
AWGS	Anschutz Wahsatch Gathering System, Inc.
bbl	Barrels
bpd	Barrels per day
CPUC	California Public Utilities Commission
DOT	Department of Transportation
EPTC	Edison Pipeline and Terminal Company
FERC	Federal Energy Regulatory Commission
Frontier	Frontier Pipeline Company
General Partner	Pacific Energy GP, Inc.
mbpd	One thousand barrels per day
OCS	Outer Continental Shelf
PEG	Pacific Energy Group, LLC
PMT	Pacific Marketing and Transportation LLC
PPS	Pacific Pipeline System LLC
Predecessor	The group of entities consisting of PPS, PMT, RMP, AREPI and RPL, for which the financial data and results of operations are presented prior to the initial public offering on July 26, 2002
RMP	Rocky Mountain Pipeline System LLC
RPL	Ranch Pipeline LLC
SEC	Securities and Exchange Commission
SJV	San Joaquin Valley
WPSC	Wyoming Public Service Commission

Information Regarding Forward-Looking Statements

This annual report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. 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, blending, transporting, storing and distributing crude oil. See "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations Risk Factors" below for a more detailed description of these 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 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.

ITEMS 1 and 2. Business and Properties

Overview

We are a Delaware limited partnership formed by Anschutz in February 2002 to acquire, own and operate the midstream crude oil business and assets held by Anschutz and its subsidiaries. On July 26, 2002, we completed an initial public offering of common limited partner units for gross proceeds of $167.7 million. We are engaged in the business of gathering, blending, transporting, storing and distributing crude oil in California and the Rocky Mountain region. We generate revenue primarily by charging tariff rates for transporting crude oil on our pipelines. We also generate revenue by blending, storing, marketing and trucking crude oil.

We have 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 Marketing and Transportation LLC ("PMT"), owner of the PMT gathering and blending facilities, (iii) Rocky Mountain Pipeline System LLC ("RMP"), owner of the Western Corridor system and the Salt Lake City Core system assets purchased from an affiliate of BP plc on March 1, 2002, (iv) Anschutz Ranch East Pipeline LLC ("AREPI"), owner of AREPI pipeline, and (v) Ranch Pipeline LLC ("RPL"), the owner of a 22.22% partnership interest in Frontier Pipeline Company ("Frontier"), a Wyoming general partnership.

We are managed by our general partner, Pacific Energy GP, Inc. ("General Partner"), a wholly owned subsidiary of Anschutz.

We have organized our business operations into two regional operating units: West Coast operations and Rocky Mountain operations.

West Coast Operations

Our West Coast operations, located in California, primarily consist of pipelines that transport crude oil produced from California's San Joaquin Valley and the California Outer Continental Shelf to refineries and terminal facilities in the Los Angeles Basin and in Bakersfield. Our pipelines are the only common carrier pipelines delivering crude oil produced in the San Joaquin Valley and in the two primary California Outer Continental Shelf producing fields, Point Arguello and the Santa Ynez Unit, to the Los Angeles Basin and Bakersfield. Our West Coast operations are headquartered in Long Beach, California, with a field office in Bakersfield. Our West Coast operations are comprised of the following pipeline assets, all of which we own 100% and operate:

Line 2000. Line 2000, an intrastate common carrier crude oil pipeline, is a 130-mile, fully insulated trunk pipeline with a permitted annual throughput capacity of 130,000 bpd.

The Line 63 system. The Line 63 system, an intrastate common carrier crude oil pipeline system, consists of a 107-mile trunk pipeline with a throughput capacity of approximately 105,000 bpd, 60 miles of distribution pipelines, 131 miles of gathering pipelines and 22 storage tanks with a total of approximately 1.2 million barrels of storage capacity.

The PMT gathering and blending system. The PMT gathering and blending system, a proprietary crude oil pipeline system located in the San Joaquin Valley, consists of 122 miles of crude oil gathering pipelines and six storage and blending facilities with approximately 254,000 barrels of storage capacity and up to 65,000 bpd of blending capacity.

We expect to expand our West Coast operations through the acquisition of the EPTC assets, which we expect to complete in the second quarter of 2003. Please read "Pending EPTC Asset Acquisition" below.

Rocky Mountain Operations

Our Rocky Mountain operations consist of pipelines that transport crude oil produced in Canada and the Rocky Mountain region to refineries in Montana, Wyoming, Colorado and Utah. Our pipelines deliver crude oil to refineries by direct connection or indirectly through connections with third party pipelines. Our Rocky Mountain operations are headquartered in Denver, Colorado, with five field offices in Wyoming, namely: Casper, Evanston, Rawlins, Thermopolis and Wamsutter. Our Rocky Mountain operations are comprised of the following assets, which form an integrated pipeline network:

Western Corridor System. The Western Corridor system, an interstate and intrastate common carrier crude oil pipeline system, extends 1,012 miles from its origination at the Canadian border near Cutbank, Montana, receives deliveries from Rangeland pipeline and Cenex pipeline, to its termination point at Guernsey, Wyoming, with connections in Wyoming to Frontier pipeline and ConocoPhillips pipeline and to the Salt Lake City Core system. This system consists of three contiguous trunk pipelines, namely: Glacier pipeline, Beartooth pipeline and Big Horn pipeline.

We own various undivided interests in each of these three pipelines, which give us rights to a specified portion of each pipeline's throughput capacity. Glacier and Beartooth pipelines provide us with approximately 25,000 bpd of throughput capacity from the Canadian border to Elk Basin, Wyoming. Big Horn pipeline provides us with approximately 33,900 bpd of throughput capacity from Elk Basin, Wyoming to Guernsey, Wyoming. We operate Beartooth and Big Horn pipelines. ConocoPhillips owns the remaining undivided interests in each pipeline and operates Glacier pipeline. 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.

Salt Lake City Core System. The Salt Lake City Core system, an interstate and intrastate common carrier crude oil pipeline system, consists of 913 miles of trunk pipelines with a combined throughput capacity of approximately 60,000 bpd to Salt Lake City, 209 miles of gathering pipelines and 29 storage tanks with a total of approximately 1.4 million barrels of storage capacity. This system originates in Ft. Laramie, Wyoming, receives deliveries from the Western Corridor system at Guernsey, Wyoming, and terminates in Salt Lake City and in Rangely, Colorado. The Rangely terminus delivers to a ChevronTexaco pipeline that serves refineries in Salt Lake City. The Salt Lake City Core system also receives deliveries from Frontier pipeline at Divide Junction, Wyoming. We own 100% of and operate the Salt Lake City Core system.

Frontier Pipeline. Frontier pipeline, an interstate common carrier crude oil pipeline, consists of a 289-mile trunk pipeline with a throughput capacity of approximately 62,200 bpd and three storage tanks with a total of approximately 274,000 barrels of storage capacity. Frontier pipeline originates in Casper, Wyoming receives deliveries from the Western Corridor system and terminates south of Evanston, Wyoming at Ranch Station, Utah. Frontier pipeline delivers crude oil to the Salt Lake City Core system and to AREPI pipeline for ultimate delivery to Salt Lake City. We own a 22.22% partnership interest in Frontier Pipeline Company, a general partnership that owns Frontier pipeline, and we serve as the operator of Frontier pipeline. Enbridge, Inc. owns the remaining partnership interest in Frontier Pipeline Company.

AREPI Pipeline. AREPI pipeline, an interstate common carrier crude oil pipeline, consists of a 42-mile trunk pipeline with a throughput capacity of approximately 52,500 bpd and three storage tanks with a total of approximately 100,000 barrels of storage capacity. AREPI pipeline originates at Ranch Station in northeast Utah, receives deliveries from Frontier pipeline, and terminates in Kimball Junction, Utah, where it delivers to a ChevronTexaco pipeline that serves refineries in Salt Lake City. We own 100% of and operate AREPI pipeline.

Business Strategy

Our principal business objective is to generate stable and increasing cash flows by becoming 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:

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

Our pipelines serve the major markets in the Rocky Mountain region, which continue to have a growing population and an increasing demand for refined products. Our Rocky Mountain area pipeline network is strategically situated to take advantage of increasing crude oil production in Canada and growing demand for refined projects in Salt Lake City and throughout the 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 and syncrude make up for a continuing decline in crude oil produced in the Rocky Mountain region.

Control our operating and capital costs. We focus on managing our costs, while recognizing our responsibilities to operate safely and maintain the operational integrity of our assets.

Pursue strategic and accretive acquisitions and new 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;
- strengthen and enhance our two existing regional operating units; and
- expand outside our two regional operating units into new growth areas.

We will also seek to capitalize on the experience of Anschutz and PPS in the development and construction of new projects by developing new midstream facilities that are complementary to our core market assets. Anschutz's experience includes construction of the Frontier and AREPI pipeline, and the more recent construction, in concert with PPS, of Line 2000.

We have been successful in the execution of this strategy of acquisition and development over the past several years and believe our acquisition history, reputation and new projects experience, along with the experience of Anschutz, will provide us with attractive opportunities in the future.

Minimize our exposure to commodity price volatility. We have historically managed our business to minimize our direct exposure to volatile commodity prices and, with the exception of our blending and marketing business, which represents a small percentage of our revenue, we do not take title to the crude oil we transport on our pipelines and store in our storage facilities. We believe this strategy will enhance our ability to make cash distributions to our unitholders.

West Coast Operations

Market Overview

Sources of Demand. Refined products such as gasoline, diesel fuel, jet fuel and heating oil are derived from crude oil. Demand for refined products directly impacts the demand for crude oil. California consumes the most gasoline of any state and more jet fuel than any other state except Texas. In addition to meeting intrastate demand, California refineries export refined products to the Arizona and Nevada markets.

California refineries have a combined crude oil refining capacity exceeding 2.0 million bpd, ranking the state third highest in the nation. The California refineries were designed to process San Joaquin Valley ("SJV") heavy crude oil and higher sulfur California Outer Continental Shelf ("OCS") crude oil, which are both transported by our pipelines.

California has three main refining centers located in the Los Angeles Basin, Central California and San Francisco, with the Los Angeles Basin refineries comprising approximately one-half of the state's capacity.

Sources of Supply. California's refineries currently process approximately 1.8 million bpd of crude oil. In addition to the local California-produced crude oil, major ports in San Francisco and Los Angeles receive waterborne Alaskan North Slope ("ANS") and foreign crude oil.

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

Line 2000

General. We own and operate 100% of Line 2000, an intrastate common carrier crude oil pipeline that transports crude oil produced in the San Joaquin Valley and California Outer Continental Shelf to refineries and terminal facilities in the Los Angeles Basin. Line 2000 is a 130-mile, fully insulated trunk pipeline originating at our Emidio Pump Station in Kern County, California. Line 2000 delivers crude oil directly and indirectly to refineries and terminal facilities in the Los Angeles Basin. The design throughput capacity of Line 2000 is approximately 145,000 bpd and the permitted annual throughput capacity is 130,000 bpd. In 2002, approximately 88,300 bpd were transported on Line 2000. Line 2000 is capable of transporting multiple batches and grades of heavy crude oil. Construction of Line 2000 began in July 1997 and was completed approximately 19 months later, in January 1999.

Line 2000 currently transports SJV heavy crude oil, California OCS crude oil and mid-barrel crude oil. In 2002, 67% of the crude oil transported on Line 2000 was SJV heavy crude oil, 22% was California OCS crude oil and 11% was mid-barrel crude oil. SJV heavy crude oil and mid-barrel crude oil are received at our Emidio Pump Station. California OCS crude oil is received from the Plains All American Pipeline at Pentland Station in Kern County, California through a pipeline we lease from a third party.

Tariffs. The CPUC regulates tariffs on Line 2000. The tariff rates we charge shippers on Line 2000 are market-based rates. We review our tariff rates on an annual basis and, subject to certain limitations set forth in our long-term transportation agreements, may raise our tariff rates in response to increases in various inflation-based indices and market factors.

The Line 63 System

General. The Line 63 system is an intrastate common carrier crude oil pipeline system that transports crude oil produced in the San Joaquin Valley and California 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, 131 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 are used primarily to facilitate the transportation of the crude oil on the pipelines. The Line 63 trunk pipeline has a throughput capacity of approximately 105,000 bpd. In 2002, approximately 74,500 bpd were transported to Los Angeles on the Line 63 trunk pipeline.

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

Tariffs. The CPUC regulates tariffs on the Line 63 system. The tariff rates we charge shippers on Line 63 are cost-based rates.

Pacific Marketing and Transportation Gathering and Blending System

General. In addition to our primary pipeline operations, we are engaged in the purchasing, gathering, blending and marketing of crude oil. Our PMT gathering and blending system is located in the San Joaquin Valley and consists of 122 miles of crude oil gathering pipelines as well as truck off-loading and blending facilities at six locations along our gathering system. Our PMT facilities have an aggregate blending capacity of approximately 65,000 bpd and an aggregate storage capacity of 254,000 barrels. Our PMT gathering and blending system is an intrastate, proprietary crude oil pipeline system and is not subject to the CPUC's jurisdiction. A substantial portion of this system was constructed in 1983.

The primary functions of our PMT operations are purchasing, gathering and blending various grades of crude oil and natural gasoline and delivering the blended product to Line 63 for transportation and sale to Los Angeles Basin refiners. In addition, we contract for third party trucks to collect crude oil from remote areas that are not connected to our gathering system. In 2002, we gathered and blended approximately 26,200 bpd of crude oil. The blended crude oil is transported on Line 63 and sold in the Los Angeles Basin. An additional 5,200 bpd of trucked crude oil was gathered and delivered directly to customers in the Los Angeles Basin or in the San Joaquin Valley. We generate net revenue from our blending activity by capturing the difference in price between the lower grade crude oil and the higher grade, blended crude oil. We believe that we are one of the largest blenders of SJV crude oil in the San Joaquin Valley.

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. We do not acquire and hold crude oil futures contracts or enter into other derivative contracts for the purpose of speculating on crude oil prices. Crude oil hedging is conducted on a limited basis to protect our inventory positions from major changes in market prices.

Customers

The following customers represent greater than 10% of net revenue for our West Coast operations for 2002: ChevronTexaco; ExxonMobil Refining & Supply Company; Shell Trading Company; Tosco Refining Company and Valero Marketing and Supply Company. On Line 2000 we have ship or pay agreements, expiring in 2009, with two customers, ChevronTexaco and Shell Trading Company, whereby they have committed to ship minimum volumes that represent approximately 69% of their actual 2002 volumes transported on Line 2000. These agreements mitigate the potential adverse consequences of our concentration of customers.

Competition

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

Line 2000 and the Line 63 system serve refineries in the Los Angeles Basin and in Bakersfield. The shippers that use our pipelines also compete with refiners in the San Francisco Bay and the central California areas for crude oil produced in the San Joaquin Valley and the California Outer Continental Shelf. Since the refiners in central California, including Bakersfield, do not have access to alternative supplies of crude oil and have the lowest transportation costs due to their proximity to the producing fields, they will usually outbid other end-users, including San Francisco Bay and Los Angeles Basin refiners, to fulfill their requirements. As a result, the San Francisco Bay and the Los Angeles Basin refiners must compete for the remaining supply of available crude oil. SJV crude oil transported to San Francisco results in a reduction in the amount of crude oil available for transportation on our pipelines. Our throughput and revenue will be adversely affected to the extent more SJV crude oil is transported to San Francisco rather than to the Los Angeles Basin. In 2002, approximately 16% of all crude oil supplied to the Los Angeles Basin, including waterborne deliveries, was transported on Line 2000 and Line 63.

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

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

Pending EPTC Asset Acquisition

On February 1, 2002, an affiliate of our General Partner entered into an agreement to acquire the terminal and pipeline assets of EPTC, a division of Southern California Edison ("SCE"). The affiliated entity that would acquire these assets is an indirect wholly owned subsidiary of Anschutz. This affiliated entity will be contributed to us on or before the completion of the acquisition. This acquisition would

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allow us to expand our distribution network to all major refineries in the Los Angeles Basin and, together with our existing West Coast operations, would create what we believe is one of the most extensive black oil storage and distribution systems in southern California. Black oil includes crude oil and other refinery feedstocks, such as gas oil. Refinery feedstocks are raw or partially refined petroleum products that are further processed by refineries. We believe this acquisition would also allow us to participate in the projected growth of marine imports of crude oil into the Los Angeles Basin.

The EPTC system is a significant crude oil storage and pipeline distribution system located in the Los Angeles Basin which specializes in storing and distributing a wide variety of crude oils and other refinery feedstocks, including gas oils. Gas oils account for approximately 40% of the total volumes handled in the EPTC system. The EPTC storage assets include 51 storage tanks with approximately 9.4 million barrels of storage capacity, allocated as follows: 35 tanks with approximately 9.0 million barrels of storage capacity are in commercial storage service, of which 2.4 million barrels are idle; 15 tanks with approximately 364,000 barrels of storage capacity are in displacement oil service; and one 40,000 barrel tank is in hydrotest water service. Over time we intend to increase available storage capacity and future revenue by reconditioning and placing in active service certain of the idle tanks included in the asset purchase. We have not established a budget or timetable for such reconditioning.

The EPTC pipeline distribution assets consist of 119 miles of large diameter pipelines, of which 70 miles are presently in black oil service. These pipelines connect the EPTC storage assets with major refineries, our Line 2000 pipeline, third-party pipelines and marine terminals in the Los Angeles Basin. Space leased on a third-party dock in the Port of Long Beach enables the EPTC system to either receive imported foreign crude oils from or export refinery feedstocks to large marine tankers. The EPTC system 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. The EPTC system 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. The EPTC assets include approximately 207,000 barrels of displacement oil that is pumped through the pipelines to assist in the transport of black oil through the system.

The EPTC system generates revenue primarily through leasing storage tank capacity to major refineries in the Los Angeles Basin. Lease rates for storage tanks are negotiated with each individual customer, resulting in private contracts with terms varying from approximately one month to five years with the majority including automatic renewal provisions. The customer contracts also contain provisions for throughput and heating charges, depending on the customer's specific needs. Although the EPTC system is subject to the jurisdiction of the CPUC, neither the CPUC nor any other regulatory agency requires EPTC to publish its lease rates. While we have filed an application with the CPUC to allow us to continue to operate the EPTC assets in this manner, we have no assurance that we will be authorized to do so.

We expect to continue providing EPTC's existing customers with the same services that have been provided by EPTC. Additionally, we will integrate the EPTC assets into our existing West Coast operations, with management, marketing and technical staff support provided by our General Partner. Our General Partner, acting on our behalf, has interviewed virtually all current SCE personnel directly involved in the operations of the EPTC assets and expects to hire a substantial number of these employees.

The purchase price for the EPTC assets is $158.2 million, plus upward adjustments for certain pre-closing capital expenditures and prepayments made by the seller relating to the purchased assets, and the value of displacement oil and warehouse inventory. We expect that these adjustments will be approximately $5 million to $10 million. We intend to finance this acquisition with a combination of proceeds from borrowings under our revolving credit facility and the issuance of additional units,

including common units, but the final structure of the acquisition financing will depend on capital market conditions and our ability to sell additional units. Please read "Item 7 Risk Factors Risks Inherent in Our Business We may be unable to compete the acquisition of the EPTC assets" below.

For accounting purposes, the EPTC acquisition will not be treated as an acquisition of a continuing business operation, but rather, will be accounted for as a purchase of assets.

We expect to complete this transaction in the second quarter of 2003. Completion of this transaction is subject to the satisfaction of a number of conditions, including approval by the CPUC and other governmental authorities. The application seeking CPUC approval of our acquisition of the EPTC assets was filed on March 22, 2002. The Coalition of California Utility Employees has opposed the sale on a number of grounds, including claims that the sale will have a negative impact on health and safety, the environment, employees, competition, rate making methodology, and that the sale is barred by a California law prohibiting the CPUC from approving any sale of utility generating facilities until 2006. The CPUC's Office of Ratepayer Advocates has opposed SCE's proposed allocation of the net gain on sale. We are unable to predict the outcome of the protests or the CPUC's disposition of our application for approval to purchase the EPTC assets. The City of Cerritos, the City of Huntington Beach, and Pacific Gas & Electric Company have also intervened in the proceeding but without protest and without alleging any issues that we believe to be material to the proceeding or our ability to complete the acquisition.

The acquisition agreement may be terminated in the event of uncured material breaches or defaults by a party to the agreement, or if the CPUC disapproves of the transaction or fails to render its approval before July 1, 2003, or by either party if the transaction has not been completed for failure of closing conditions by July 1, 2003. Moreover, some of the assets that we expect to acquire may ultimately not be acquired if necessary third-party consents cannot be obtained or if certain casualty events damage or destroy those assets. Accordingly, there is no assurance that we will ultimately acquire the EPTC assets in the second quarter of 2003 or at all.

Rocky Mountain Operations

On March 1, 2002, we purchased from BP, a major integrated oil company, certain of its Rocky Mountain crude oil pipeline assets, including the Western Corridor system and Salt Lake City Core system assets for approximately $106.0 million. We have been and plan to continue operating these assets in a manner significantly different from the manner in which BP operated them. BP operated the Western Corridor system assets to a significant extent as a "proprietary" pipeline system to support its affiliated refinery operations, not with the primary goal of maximizing pipeline profits. As an independent pipeline owner and operator, with no refinery operations, we have been and will continue to direct our efforts towards maximizing pipeline profits. In addition, we implemented a new marketing and business development function that actively solicits new third-party shippers, including all refiners in the Rocky Mountain region.

Market Overview

Sources of Demand. The 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. We believe that this sustained population growth will result in an increase in the use of refined products and requirements for crude oil. The fifteen refineries in the region consume more than 500,000 bpd of crude oil.

While we transport crude oil that is delivered throughout the Rocky Mountain region, Salt Lake City, Utah is our primary market. Utah is one of the fastest growing states in the country and Salt Lake City is its most populous city. Among other factors, Salt Lake City's strong population growth is expected to stimulate growth in refined product demand, particularly gasoline and jet fuel. Additionally, Salt Lake City refiners supply refined products to markets in Utah, Wyoming, Idaho, Oregon, Washington and Nevada. Salt Lake City's refining center has a total capacity of 163,000 bpd.

Sources of Supply. The crude oil supplying the Rocky Mountain refining centers is a combination of Rocky Mountain and Canadian crude oil, including Canadian syncrude. We believe Rocky Mountain crude oil production will continue to decline and imports of Canadian crude oil, including syncrude, will increase to replace declining Rocky Mountain production.

One major source of the increase in crude oil production in western Canada is the increase in the production of Canadian syncrude. Canadian syncrude, or synthetic crude oil, is crude oil produced from bitumen, a viscous substance abundant in the oil sand deposits in western Canada. Production of Canadian syncrude is expected to increase in the future, which will benefit our Rocky Mountain operations in two ways: first, there will be more Canadian syncrude destined for the Rocky Mountain refining centers served by our pipelines, and second, more Canadian crude oil should be transported on our pipelines as Canadian syncrude displaces it from current Canadian markets.

Western Corridor System

General. We own an undivided interest in each of three contiguous pipelines that make up the Western Corridor system, a 1,012-mile interstate and intrastate common carrier crude oil pipeline system that originates at the Canadian border near Cutbank, Montana, receives deliveries from the Rangeland pipeline and the Cenex pipeline, and terminates in Guernsey, Wyoming. Our ownership interest in each of the three pipelines 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 than the figures specified below if the crude oil being transported is more viscous, or heavier, than that which is used as the benchmark to determine the amount of our throughput capacity. ConocoPhillips, the co-owner of the Western Corridor pipeline, owns the remaining undivided interest in each of these pipelines. In 2002, approximately 63% of the crude oil transported on our portion of the Western Corridor system's throughput capacity was Canadian crude oil and the remaining 37% was Rocky Mountain crude oil. The Western Corridor system does not currently transport Canadian syncrude. The pipelines comprising the Western Corridor system were constructed at various times, with Glacier pipeline constructed in 1960, Beartooth pipeline in 1996 and Big Horn pipeline in 1944.

Each pipeline 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 trunk pipeline, both extending from the Canadian border near Cutbank, Montana to Billings, Montana. Shipments on Glacier pipeline can be delivered either to refineries in Billings, Montana or into Beartooth pipeline. In 2002, approximately 9,300 bpd of Canadian crude oil was transported on our Glacier pipeline throughput capacity. ConocoPhillips is the operator of Glacier Pipeline.

> *Beartooth Pipeline.* We own a 50% undivided interest in Beartooth pipeline, which provides us with approximately 25,000 bpd of throughput capacity. Beartooth pipeline is a 76-mile, 12-inch trunk pipeline from Billings, Montana to Elk Basin, Wyoming. All shipments on Beartooth pipeline are delivered into Big Horn pipeline. In 2002, approximately 8,900 bpd of Canadian crude oil was transported on our Beartooth pipeline throughput capacity. Beartooth pipeline was constructed to connect Glacier pipeline with Big Horn pipeline. We operate Beartooth pipeline.

> *Big Horn Pipeline.* We own a 57.6% undivided interest in Big Horn pipeline, which provides us with approximately 33,900 bpd of throughput capacity. Big Horn pipeline consists of a 250-mile,

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> 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 at Guernsey, Wyoming. In 2002, approximately 8,900 bpd of Canadian crude oil and 6,100 bpd of Rocky Mountain crude oil was transported on our Big Horn throughput capacity. We operate Big Horn pipeline.

Under our contracts with ConocoPhillips, we manage our undivided interest in the Western Corridor system independently of ConocoPhillips. 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. We manage operating expenses and capital expenditures jointly with ConocoPhillips. We approve and monitor budgets and are allocated our share of the expenses based on our ownership percentage.

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

Tariffs. The Federal Energy Regulatory Commission ("FERC") and the Wyoming Public Service Commission ("WPSC") each regulate various tariffs on the Western Corridor system. The tariff rates we charge shippers on the Western Corridor system are cost-based rates.

We are involved in a proceeding at the FERC relating to a complaint filed by Sinclair Oil Corporation challenging our interstate rates on the Western Corridor system. Please read "Item 3 Legal Proceedings" below.

Salt Lake City Core System

General. We own 100% of and operate the Salt Lake City Core system, an interstate and intrastate common carrier crude oil pipeline system that transports crude oil produced in Canada and the 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 60,000 bpd to Salt Lake City. The Salt Lake City Core system consists of 913 miles of trunk pipelines, 209 miles of gathering pipelines and 29 storage tanks with approximately 1.4 million barrels of storage capacity. These storage assets are used primarily to facilitate the transportation of the crude oil on the pipelines. The main trunk pipeline originates in Ft. Laramie, Wyoming, receives deliveries from the Western Corridor system at Guernsey, Wyoming, and extends west to Wamsutter, Wyoming, where it divides, with a northern segment continuing west, eventually delivering to Salt Lake City, and a southern segment extending south to Rangely, Colorado, where it delivers to a ChevronTexaco pipeline that serves Salt Lake City. In 2002, the northern segment delivered approximately 41,600 bpd and the southern segment delivered approximately 17,600 bpd to Salt Lake City. In addition, 11,500 bpd were transported from Reno to Casper, Wyoming and 500 bpd from Guernsey to Ft. Laramie, Wyoming. In 2002, virtually all of the crude oil transported on the Salt Lake City Core system was Rocky Mountain crude oil. Construction of the Salt Lake City Core system began in 1939 with construction of additional pipelines and facilities continuing until 1991.

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

Tariffs. The FERC and the WPSC each regulate various tariffs on the Salt Lake City Core system. The tariff rates we charge on the Salt Lake City Core system are cost-based rates.

Frontier Pipeline

General. We own 22.22% of Frontier Pipeline Company, a general partnership that owns 100% of Frontier pipeline, and we serve as its operator. Enbridge, Inc., an unrelated third party, owns the remaining 77.78% of Frontier Pipeline Company. Frontier pipeline is an interstate common carrier crude oil pipeline that consists of a 289-mile trunk pipeline with a throughput capacity of approximately 62,200 bpd, which is expandable with the addition of pump stations to 109,000 bpd, and three storage tanks with approximately 274,000 barrels of storage capacity. These storage assets are used primarily to facilitate the transportation of the crude oil on the pipelines. Frontier pipeline originates in Casper, Wyoming, a hub for the distribution of crude oil produced in Canada and in the Rocky Mountain region, receives deliveries from the Western Corridor system. Frontier pipeline also receives Canadian crude oil, including Canadian syncrude, via connections with Express pipeline, and other connecting carriers in Casper, Wyoming. Frontier pipeline also transports crude oil received from producing fields in Montana and northeast Wyoming through connections with the Western Corridor system and third-party pipelines. Frontier pipeline delivers crude oil into the Salt Lake City Core system and to AREPI pipeline for ultimate delivery into Salt Lake City. In 2002, approximately 44,400 bpd were transported on Frontier pipeline. Frontier pipeline was constructed in 1983.

Tariffs. The FERC regulates tariffs on Frontier pipeline. The tariff rates we charge on Frontier pipeline are cost-based rates.

AREPI Pipeline

General. We own 100% of and operate AREPI pipeline, an interstate common carrier crude oil pipeline. AREPI pipeline consists of a 42-mile trunk pipeline with a throughput capacity of approximately 52,500 bpd and three storage tanks with approximately 100,000 barrels of storage capacity. These storage assets are used primarily to facilitate the transportation of the crude oil on the pipelines. The trunk pipeline originates 21 miles south of Evanston, Wyoming at Ranch Station, Utah, receives deliveries from Frontier pipeline, and terminates at Kimball Junction, Utah, where it delivers to a ChevronTexaco pipeline serving the Salt Lake City refinery market. At present, AREPI pipeline is the principal source of supply for this ChevronTexaco pipeline between Kimball Junction and Salt Lake City. AREPI pipeline is capable of transporting multiple grades of Canadian crude oil, including Canadian syncrude, as well as multiple grades of crude oil produced in the Rocky

Mountain region. In 2002, approximately 45,600 bpd were transported on AREPI pipeline. AREPI pipeline was constructed in 1987.

We believe AREPI pipeline is strategically positioned with respect to the refineries serving the Salt Lake City area because of its connection to Frontier pipeline. This connection, which was completed in 1993 at Frontier Pipeline's Ranch Station, increased the volume of crude oil shipped on AREPI pipeline and enabled AREPI pipeline to deliver Canadian crude oil, including Canadian syncrude, to refineries in Salt Lake City. We believe that we will continue to experience volume growth on AREPI pipeline as the decline in crude oil production from Rocky Mountain fields increases demand for Canadian crude oil and syncrude.

Tariffs. The FERC regulates tariffs on AREPI pipeline. The tariff rates we charge on AREPI pipeline are cost-based rates.

During 2002, we were involved in tariff rate case litigation before the FERC with respect to AREPI pipeline. However, all issues in that litigation were resolved pursuant to a settlement agreement executed in March 2002. Pursuant to the settlement agreement, we reduced AREPI's local tariff rate and AREPI's division of the joint tariff rate filed by Express pipeline, which was subsequently cancelled.

Customers

The following customers represent greater than 10% of net revenue for our Rocky Mountain operations for 2002: BP; ChevronTexaco; ConocoPhillips and Tesoro. We have not entered into any transportation contracts with respect to crude oil transported on the Rocky Mountain pipelines.

Competition

We are not aware of any active projects to build new crude oil pipeline capacity into the Salt Lake City market.

We compete against several crude oil pipelines in the Rocky Mountain region. Each pipeline is described below:

Express/Platte Pipeline. Express/Platte Pipeline, which receives deliveries from Frontier pipeline, transports Canadian crude oil, including syncrude, into the Rocky Mountain region. The Express pipeline originates in Hardisty, Alberta and transports crude oil from the Canadian border into Montana and Casper and Guernsey, Wyoming. We believe that transportation of the expected increased Canadian crude oil production will require the capacity of both the Express pipeline and our Rocky Mountain systems. In January 2003, it was announced that the Express/Platte Pipeline had been sold to a Canadian consortium led by BC Gas, which will also be its operator. The future impact of this transaction on us is unknown.

Cenex Pipeline. The Cenex pipeline moves crude oil from Canada and Montana to refineries in Billings and Laurel, Montana. This pipeline can also receive or deliver Canadian crude oil to and from the Western Corridor system at the Cutbank, Montana station on Glacier pipeline. The Cenex pipeline and the Western Corridor system compete for delivery of crude oil to the Billings and Laurel refineries. However, the Cenex pipeline is the only source of Canadian Bow River crude oil transported on the Western Corridor system for eventual delivery to markets in Wyoming, Colorado and Utah.

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

Eastern Corridor System. The Eastern Corridor system, which delivers to the Salt Lake City Core system at Fort Laramie, Wyoming, is made up of pipeline systems that deliver crude oil from Canada, eastern Montana and western North Dakota to customers in Wyoming, Colorado and Utah. Although the Salt Lake City Core system benefits from the tariff revenue as crude oil is delivered from the Eastern Corridor system to the Salt Lake City core system for transportation to Salt Lake City, the Eastern Corridor system competes with the Western Corridor system.

ConocoPhillips Western Corridor. ConocoPhillips owns an undivided interest in the Glacier, Beartooth and Big Horn pipelines. ConocoPhillips sets its tariff rates, markets its throughput capacity, and accounts for its revenue separate from and in competition with us.

Construction of a refined products pipeline system able to deliver refined products from El Paso, Texas, into the Rocky Mountain region has been discussed by various companies for a number of years. The goal of such a pipeline would be to transport refined products from refineries on the Texas Gulf Coast to Salt Lake City via a series of connected pipeline segments. If built, such a pipeline would compete with our Rocky Mountain operations. Such a project would require significant modifications to existing pipelines as well as the construction of new pipelines. Based on the information currently known to us, we do not believe such a pipeline will be constructed in the near future.

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

Pipeline Operation and Control

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

We operate all of our pipelines and the Frontier pipeline from three consoles that are manned 24 hours a day by our pipeline system controllers. Our Long Beach control center is housed in a stand-alone building designed with special earthquake protection and multiple security systems to ensure that only authorized personnel enter. In addition, 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.

In general, the SCADA systems we use provide continuous, real-time, 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. Numerous software applications have been integrated into our SCADA systems to assist our pipeline system controllers with certain functions, such as product batch tracking, historical event analysis, trend monitoring, flow balance and leak detection monitoring. Our automatic report generation systems supply data to our marketing, operations and maintenance personnel.

In addition to continuous monitoring, our SCADA systems provide our pipeline system controllers with the ability to remotely control all aspects of systems operation, including starting and stopping pumps, opening and closing valves, and switching into and out of storage tanks. Our SCADA systems are programmed to alert the pipeline system controllers any time that operational conditions fall outside established parameters. Upon detection of an irregularity, our pipeline system controllers can shut down the affected pipeline by remotely stopping pumps and closing block valves located along the various systems.

Safety and Maintenance

Our 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"), amends the HLPSA in several important respects. It 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. In August 2000, the DOT adopted pipeline operator qualification rules requiring minimum qualification requirements for personnel performing operations and maintenance activities on hazardous liquid pipelines. The DOT has also approved regulations that 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, which was signed into law on December 17, 2002, imposes additional requirements on pipeline operators. The new 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. Two segments of our Line 63 system, totaling 10.9 miles of pipeline, are included on the higher risk pipeline list. These segments have been internally tested as part of our smart pig program and, in the absence of additional reportable leaks, 7.1 miles of such pipeline will be removed from the list in May 2003, and 3.8 miles of such pipeline will be removed in February 2005.

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

We monitor the structural integrity of selected segments of our pipelines through a program of periodic internal inspections using electronic internal inspection tools, or "smart pigs." These tools analyze the interior of our pipelines, providing data as to wall thickness, corrosion and other anomalies that might indicate possible pipeline failure. Our engineers conduct a detailed review of the inspection data and make repairs as required to ensure the integrity of the pipelines. We have developed an integrity management program in accordance with DOT 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.

Since 1999, when we began our smart pigging program in California, we have internally inspected 100% of our California trunk pipelines and 26% of our gathering and distribution lines. In our Rocky Mountain segment approximately 43% of the pipelines we operate, excluding the Frontier pipeline, have been smart pigged in the last five years. The Frontier pipeline is scheduled to be smart pigged in 2003. We anticipate spending approximately $1.4 million in 2003 to continue with these inspections.

The workplaces associated with our 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.

Tariff Rate Regulation

Interstate Pipelines

General Federal Regulation. Our interstate common carrier crude oil pipeline operations are subject to tariff rate regulation by the FERC under the Interstate Commerce Act. The Interstate Commerce Act requires that tariff rates for crude oil pipelines, which for tariff rate purposes includes refined product pipelines, (crude oil and refined products pipelines are referred to collectively as "petroleum pipelines" in this section), be just and reasonable and non-discriminatory. The Interstate Commerce Act permits challenges to proposed new or changed tariff rates by protest and challenges to tariff rates that are already on file and in effect by complaint. Upon the appropriate showing, a successful complainant may obtain damages or reparations for generally up to two years prior to the filing of a complaint.

The FERC is authorized to suspend the effectiveness of a 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 rates the FERC determines to be lawful and the rates under investigation. In addition, the FERC may order the pipeline to change its tariff rates prospectively to the lawful level. In general, and except as discussed below with respect to indexed and "grandfathered" rates, petroleum pipeline tariff rates must be cost-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 in certain circumstances such as when the FERC determines that a particular transportation market is competitive; we presently have an application for authority to use market-based rates on our Western Corridor system pending with the FERC. Please read "Item 3 Legal Proceedings" below.

The FERC has adopted a trended original cost methodology as the general methodology to be used in setting cost-based tariff rates for petroleum pipelines. The trended original cost methodology is similar to the depreciated original cost methodology generally used by the FERC to set rates for

natural gas pipelines and electric utilities, with the primary difference being that under the trended original cost methodology, the inflation component of the petroleum pipeline's equity return is extracted from the equity return and added to the pipeline's equity rate base. The write-up is then amortized over the life of the pipeline's property, similar to the recovery of depreciation.

Index-Based Rates, Energy Policy Act of 1992 and Grandfathered Rates. 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 in either the economic circumstances of 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 are 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 will be subject to protest, but the scope of the protest proceeding will be 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, whether grandfathered or whether 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 to indexing and the cost-of-service approach in certain specified circumstances.

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 of such assessments in 2000. In an order issued December 14, 2000, the FERC concluded the existing index had closely approximated the actual cost changes in the petroleum pipeline industry and that use of the rate index continued to satisfy the mandates of the Energy Policy Act. The Association of Oil Pipe Lines petitioned for judicial review of that decision to the U.S. Court of Appeals for the District of Columbia Circuit ("D.C. Circuit"), arguing that the annual adjustment should be based on the full producer price index, without the one percentage point deduction. On March 1, 2002, the D.C. Circuit found that the FERC had not provided adequate justification for retention of the existing rate-index and remanded the case to the

FERC for further proceedings. On February 20, 2003, the FERC issued an order on remand in which it changed the rate index to the producer price index for finished goods, but without the one percentage point deduction. The FERC made the change on a prospective basis, however, it does allow oil pipelines to recalculate their maximum ceiling rates as though the new rate index had been in effect since July 1, 2001. We cannot predict whether the FERC's February 2003, order will be challenged; however, we do not expect the order to have a material impact on our results of operations for 2003.

Recent Developments Regarding Petroleum Pipeline Rates. Another development affecting petroleum pipeline ratemaking arose in Opinion No. 397, involving Lakehead Pipe Line Company, L.P., a partnership that operates a crude oil pipeline. In Opinion No. 397, the FERC concluded that Lakehead was entitled to include in calculating its rates an income tax allowance only with respect to the portion of its earnings that are allocated to its partners that are corporations, rationalizing that income allocated to other partners would be subject only to one level of taxation. The parties subsequently settled the case, so there was no judicial review of the FERC's decision.

Two other FERC proceedings, both involving SFPP, L.P., ("SFPP") could result in changes to the FERC's decision in Opinion No. 397 regarding the income tax allowance, as well as to other elements of the FERC's rate methods for petroleum pipelines. SFPP is now a subsidiary of a publicly traded limited partnership engaged in the transportation of petroleum products. In the first proceeding, the FERC issued Opinion No. 435 in which the FERC, among other things, affirmed Opinion No. 397's determination that there should not be a corporate income tax allowance built into a petroleum pipeline's rates for income attributable to noncorporate partners. Several parties sought rehearing of various issues addressed in Opinion 435, including its decision on the income tax allowance issue. The FERC addressed the requests for rehearing in Opinion No. 435-A, issued on May 17, 2000, in Opinion No. 435-B, issued on September 13, 2001, and in two subsequent orders. Several parties to the case have filed for judicial review before the D.C. Circuit of one or more of the FERC's decisions in this proceeding. While the ultimate outcome of the income tax allowance issue and other questions that are considered on review 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.

The 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. An initial decision by the administrative law judge is expected in 2003. We cannot predict at this time what effect this proceeding will have on the ability of parties to challenge grandfathered rates.

Our Pipelines. The FERC generally has not investigated interstate rates on its own initiative when those rates have not been the subject of a protest or a complaint by a shipper. A shipper or other party having a substantial economic interest in our rates could, however, challenge our rates. In response to such challenges, the FERC could investigate our rates. To the extent that a complainant challenged an interstate rate that is grandfathered under the Energy Policy Act, the complainant would have to first demonstrate a substantial change since the date of enactment of the Act, in either the economic circumstances or the nature of the service that formed the basis for the rate. A complainant could assert that the creation of Pacific Energy Partners, L.P. itself constitutes such a change, an argument that has been raised in the second SFPP proceeding discussed above, but which has not been specifically addressed by the FERC. 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.

We are involved in a proceeding at the FERC relating to a complaint filed by Sinclair Oil Corporation challenging our interstate rates on the Western Corridor system. We presently have an application for authority to use market-based rates on our Western Corridor system pending with the FERC. Please read "Item 3 Legal Proceedings" below.

Intrastate Pipelines

California. The CPUC regulates the tariffs we charge shippers on Line 2000 and the Line 63 system. Line 2000 has market-based tariff rates and the Line 63 system has cost-based tariff rates.

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

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

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

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

In Decision 94-10-044, which authorized SCE to utilize its fuel oil pipeline facilities for services to third parties, the CPUC authorized SCE and its EPTC division to negotiate and execute contracts with customers for pipeline transportation, storage and other utility services. In addition, the CPUC agreed that SCE was not required to submit such contracts for prior CPUC review or to make such contracts available for public inspection. In the joint application to the CPUC that we filed with SCE on March 22, 2002 for authority to purchase the EPTC fuel oil pipeline and station facilities, we requested that the CPUC allow us to continue the same methodology for establishing storage and transportation fees that it had authorized for SCE and its EPTC division. However, at this time, we cannot assure you that the CPUC will do so.

Montana. 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.

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

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

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

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

The adoption by us of a cost-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.

Environmental Regulation

General

Our 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 and other liquid hydrocarbon materials. Furthermore, violations of environmental laws or regulations can result in the imposition of significant administrative, civil and criminal fines and penalties and, in some instances, 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, claims made by neighboring landowners and other third parties for personal injury and property damage, and fines or penalties for any related violations of environmental laws or regulations.

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

Air Emissions

Our operations are subject to the Federal Clean Air Act and comparable state and local statutes. 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 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 achievable 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 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. The local air quality regulations also 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.

Hazardous Substances and Waste Management

The Federal Comprehensive Environmental Response, Compensation and Liability Act, ("CERCLA") (also known as the "Superfund" law), and similar state laws, impose liability without regard to fault or the legality of the original conduct, on certain classes of persons, including the owners or operators of waste disposal sites 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 generate some wastes that fall within the definition of a "hazardous substance." We may, therefore, be jointly and severally liable under CERCLA for all or part of any costs required to clean up and restore sites at which such wastes have been disposed. 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 operations also generate both hazardous and nonhazardous wastes that are subject to the requirements of the Federal Resource Conservation and Recovery Act ("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 a apply to a broader range of wastes.

Water

The Federal Water Pollution Control Act, also known as the Clean Water Act, and similar state laws place strict limits on the discharge of contaminants into federal and state waters. Regulations under these laws prohibit such discharges unless authorized by and in compliance with a National Pollutant Discharge Elimination System ("NPDES"), permit or an equivalent state permit. The Clean Water Act and analogous state laws allow significant penalty assessments for unauthorized releases of water pollution 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 pollution into groundwater. We believe that we will be able to obtain, or be covered under, any required Clean Water Act permits and that compliance with the conditions of those permits will not have a material effect on our operations.

The Oil Pollution Act ("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. In addition, the U.S. Department of Transportation Office of Pipeline Safety has approved our oil spill emergency response plans.

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 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 and groundwater contamination in some locations. Such contamination caused by historical activities is not unusual within the petroleum pipeline industry. We 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. Under these laws, we could incur substantial expense to remediate any such contamination, including contamination caused by prior owners or operators. We are currently addressing soil or groundwater contamination at various properties through assessment, monitoring and remediation programs with oversight by the applicable state agencies. In connection with our acquisition of ARCO Pipe Line Company ("ARCO")'s ownership interest in PPS in 2001, we assumed a $2.6 million liability representing the estimated cost of remediating the properties that had been contributed to PPS by ARCO in 1999. However, there is no guarantee that the actual remediation costs or associated liabilities will not exceed this amount. Please also read "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations Recent Accounting Pronouncements" below.

Title to Properties

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, country 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, therefore 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 the common carrier pipelines are either on land that we own in fee, on property under a long-term lease or, in several cases, held under a Special Use Permit from the United States Department of the Interior. Our headquarters and control center are located on a 27.50-acre property in Long Beach that we own in fee. Crude oil storage tanks, maintenance facilities

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and warehouse space are also located on this property. Our Bakersfield office and maintenance facility is located in a 15,000 square foot combination office space/warehouse building, occupied pursuant to a long-term lease. To support our Rocky Mountain operations, we have crude oil storage tanks and maintenance and warehouse facilities on land we own in fee in Casper, Wyoming. Our Evanston, Wyoming office and maintenance facility is occupied pursuant to a long-term lease.

We believe we have satisfactory title or other right to all of our material assets. Title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with acquisition of real property, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, and minor easements, restrictions, and other encumbrances to which the underlying properties were subject at the time of acquisition by our predecessor or us. However, we believe that none of these burdens will materially detract from the value of these properties or from our interest in these properties or will materially interfere with their use in the operation of our business. Please read "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Right-of-Way Obligations."

Employees and Labor Relations

We do not have any employees. Our General Partner employs approximately 215 employees who directly support our operations. 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. None of our General Partner's employees are subject to a collective bargaining agreement. Our General Partner considers its employee relations to be good.

ITEM 3. Legal Proceedings

On March 15, 2002, Sinclair Oil Corporation ("Sinclair") filed a complaint with the WPSC alleging that RMP's common stream rules and specifications and RMP's refusal to prohibit certain types of crude oil diluents from the common stream, all in respect of the Big Horn segment of the Western Corridor system, are adverse to Sinclair and the public interest. A hearing on Sinclair's complaint was held by the WPSC in October 2002, and briefs were filed by the parties in January 2003. In general, Sinclair is seeking an order from the WPSC requiring RMP to segregate certain crude oil types that are objectionable to Sinclair from the common stream. No decision has been issued by the WPSC. While we cannot predict the outcome of this dispute, we do not expect this matter to have a material adverse effect on the Partnership's financial position, results of operations or liquidity.

On March 19, 2002, RMP filed revised tariffs that reduced the rates we charge for interstate transportation service on the Western Corridor system. On April 15, 2002, Sinclair filed a complaint with the FERC challenging these rates. In its complaint, Sinclair alleges that the reduced rates exceed just and reasonable levels. RMP filed a general denial of Sinclair's allegations, as well as a motion for dismissal of Sinclair's complaint and, alternatively, a motion asking the FERC to hold Sinclair's complaint in abeyance pending the FERC's decision on an application for market-based rates, which, if granted, would allow RMP to set its tariff rates in response to competitive forces, rather than by reference to cost of service. Without ruling explicitly on either of RMP's motions, the FERC, in February 2003, ordered that a hearing be held to determine the issues raised by Sinclair's complaint. RMP has filed a motion for rehearing of that order. While we cannot predict the outcome of this dispute, we do not expect this matter to have a material adverse effect on the Partnership's financial position, results of operations or liquidity.

The application for market based rates referenced in the preceding paragraph was filed by RMP on July 22, 2002. Protests to our application for market-based rates were filed with the FERC by Sinclair, Tesoro Refining and Marketing Company, ConocoPhillips and Chevron Products Company.

These protests variously allege that our application incorrectly defined the relevant geographic and product markets and that, if such markets are properly defined, we should be found to have market power in those markets. The FERC has issued no rulings in response to this application. While being granted the right to set tariff rates for the Western Corridor on the basis of market considerations, rather than cost of service, would give RMP greater convenience and a desirable degree of pricing flexibility and responsiveness, a failure to prevail on its application, in whole or in part, would not be expected to have a material adverse effect on the Partnership's financial position, results of operations or liquidity.

We are subject to numerous federal, state and local laws which regulate the discharge of materials into the environment or that otherwise relate to the protection of the environment. We currently have an environmental remediation liability resulting from our acquisition of ARCO's interest in PPS in 2001. The accrued liability was $2.6 million at December 31, 2002 and was classified in the consolidated balance sheets within "other liabilities." However, the total 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 our 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 parties. Please also read "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations Recent Accounting Pronouncements" below.

We are involved in various other litigation and claims arising out of 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 expect to have a material adverse effect on our business, financial position, results of operations or liquidity.

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 2002.

ITEM 5. Market for Registrant's Common Equity and Related Stockholder Matters

Our common units are listed on the New York Stock Exchange under the symbol "PPX". At the close of business on December 31, 2002, we had 35 holders of record of our common units, representing approximately 8,000 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 since the close of our initial public offering on July 26, 2002 are as follows:

	Price Range			
	High	Low	Cash Distributions(2)	Payment Date
Third Quarter 2002(1)	$ 20.28	$ 18.20	$ 0.3368	November 14, 2002
Fourth Quarter 2002	$ 20.10	$ 18.65	$ 0.4625	February 14, 2003

(1) For the period from July 26, 2002 through September 30, 2002

(2) Distributions declared associated with each respective quarter. The third quarter distribution of $0.3368 per limited partner unit was pro-rated for the period from July 26, 2002, the date of the closing of our initial public offering of common units, through

September 30, 2002, and is equivalent to a full quarterly distribution of $0.4625 per limited partner unit.

On July 22, 2002, the registration statement on Form S-1 (SEC File No.: 333-84812), as amended, that we filed with the Securities and Exchange Commission ("SEC") relating to our initial public offering became effective. The managing underwriter was Salomon Smith Barney. The closing date of our initial public offering was July 26, 2002 and on that date we sold 8,600,000 common units to the public at a price of $19.50 per common unit, or $167.7 million. The underwriting discount on this sale was approximately $11.5 million. Concurrent with the closing of our initial public offering, PEG borrowed $225.0 million under its term loan facility with Fleet National Bank and other lenders and incurred approximately $5.3 million of debt issuance costs and related expenses. A summary of the proceeds received and use of proceeds from these transactions is as follows (in thousands):

Proceeds received:		
Sale of common units	$	167,700
Borrowing under term loan facility		225,000
Total proceeds received	$	392,700
Use of proceeds from sale of common units:		
Underwriting discount	$	11,500
Professional fees and other offering costs(1)		4,900
Repayment of debt(1)		151,300
Total use of proceeds from the sale of common units		167,700
Use of proceeds from term loan facility:		
Debt issuance costs and related expenses	$	5,300
Repayment of debt		114,600
Distributions to General Partner		105,100
Total use of proceeds from term loan facility		225,000
Total use of proceeds	$	392,700

(1) Based upon the amount of professional fees and other offering costs, net proceeds from the sale of common units used to repay debt amounted to $151.3 million. The remaining outstanding debt balance of $2.4 million was repaid by PEG.

On July 26, 2002, as part of the consideration for the contribution of assets and liabilities by our General Partner and its affiliates to the Partnership, we issued to our General Partner 1,865,000 common units and 10,465,000 subordinated units representing limited partner interests as well as rights to receive incentive distributions in an offering exempt from registration under Section 4(2) of the Securities Act of 1933.

Cash Distribution Policy

We are required, within 45 days after the end of each quarter, to distribute all of our available cash, if any, to unitholders of record on the applicable record date. 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 are necessary or appropriate in the reasonable discretion of our General Partner 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 unitholders and 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.

We intend to make a minimum quarterly distribution on each common unit and subordinated unit of $0.4625, or $1.85 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.

Our ability to distribute available cash is contractually restricted by the terms of our credit agreement. Our credit agreement contains covenants requiring us to maintain certain financial ratios. We are prohibited from making any distribution to unitholders if the distribution would cause an event of default or if an event of default exists, under our credit agreement.

Operating Surplus

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.

Operating surplus generally means:

our cash balance on July 26, 2002, the closing date of our initial public offering; plus

$15.0 million; plus

all of our cash receipts after 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 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 after 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.

Capital surplus generally means:

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.

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 at closing 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

During the subordination period, the common units will be entitled to receive quarterly 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 subordination period will generally end 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.

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

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

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

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

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

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

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

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

Upon expiration of the subordination period, each outstanding subordinated unit will automatically convert into one common unit and will then participate, pro rata, with the other common units in any distributions of available cash. In addition, if the unitholders remove our General Partner other than

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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.

Distributions 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 After the Subordination Period

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

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

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

Incentive Distribution Rights

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

If for any quarter:

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

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

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

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

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

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

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

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

Percentage Allocations of Available Cash from Operating Surplus

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

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

ITEM 6. Selected Financial Data

The following table shows selected financial and operating data of Pacific Energy Partners, L.P., the successor to Pacific Energy (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 PEG, whose subsidiaries consist of (i) PPS, owner of Line 2000 and the Line 63 system, (ii) PMT, owner of the PMT gathering and blending assets, (iii) RMP, owner of the Western Corridor system and the Salt Lake City Core system assets purchased from an affiliate of BP plc on March 1, 2002, (iv) AREPI, owner of AREPI pipeline, and (v) RPL, the owner of a 22.22% partnership interest in Frontier. Prior to July 26, 2002, the financial and operating data for PPS, PMT, RMP, AREPI and RPL, are presented on a combined basis and constitute the Predecessor. Subsequent to July 26, 2002, the financial and operating data of PPS, PMT, RMP, AREPI and RPL are presented on a consolidated basis as successor to the Predecessor. The financial data for 2000 and 2001 are derived from the audited combined financial statements of Pacific Energy (Predecessor).

The financial data for 2000 and 2001 does not include the financial position or results of operations associated with the Western Corridor system or Salt Lake City Core system assets purchased from BP on March 1, 2002. The financial data for 2002 includes the financial position and results of operations associated with ten months of ownership of the Western Corridor system and Salt Lake City Core system assets. Accordingly, for 2000 and 2001, references to our Rocky Mountain operations in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in the consolidated financial statements include only AREPI pipeline and Frontier pipeline (under the equity method) and do not include the Western Corridor system or Salt Lake City Core system assets.

The financial data for 2000 does not include the financial position or results of operations associated with the PMT assets purchased from EOTT Energy Partners on July 1, 2001. The financial data for 2001 includes the financial position and results of operations associated with six months of ownership of the PMT assets. The financial data for 2002 includes the financial position and results of operations associated with a full year of ownership of the PMT assets.

The financial data does not include the financial position or results of operations associated with the pending EPTC asset acquisition.

We define EBITDA as net income less interest income, plus interest expense and depreciation and amortization. The Partnership is not a taxable entity. EBITDA provides additional information for evaluating our ability to make the minimum quarterly distribution and is presented solely as a supplemental measure. You should not consider EBITDA as an alternative to net income, income before taxes, cash flows from operations, or any other measure of financial performance presented in accordance with accounting principles generally accepted in the United States. Our EBITDA may not be comparable to EBITDA or similarly titled measures of other entities as other entities may not calculate EBITDA in the same manner as we do.

Maintenance 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.

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

Form 10-K. The table should also be read together with "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations".

	Years Ended December 31,		
	Pacific Energy Partners, L.P.		
	2000	2001	2002(1)
	(in thousands)		
Consolidated Statements of Income:			
Revenue:			
Pipeline transportation	$ 71,419	$ 66,236	$ 102,353
Crude oil sales, net of purchases(2)		9,028	22,158
Net revenue before operating expenses	71,419	75,264	124,511
Expenses:			
Operating	26,988	34,382	54,343
Transition costs		220	2,634
General and administrative	2,672	4,134	8,622
Rate case litigation settlement(3)		1,853	
Depreciation and amortization	11,873	11,368	15,919
Total expenses	41,533	51,957	81,518
Share of net income of Frontier(4)	1,738	1,569	1,347
Operating income	31,624	24,876	44,340
Other income	357	467	516
Interest income	474	320	385
Interest expense	(18,115)	(10,056)	(11,667)
Net income	$ 14,340	$ 15,607	$ 33,574
Other Financial Data:			
EBITDA(5)	$ 43,854	$ 36,711	$ 60,775
Net cash provided by operating activities	26,319	26,406	45,793
Net cash used in investing activities(6)	(3,487)	(37,203)	(101,311)
Net cash provided by (used in) financing activities(7)	(17,571)	8,044	69,880
Capital expenditures:			
Maintenance	$ 1,662	$ 3,381	$ 2,649
Transitional			2,061
Expansion	1,825	2,433	1,290
Total capital expenditures	$ 3,487	$ 5,814	$ 6,000
Balance Sheet Data (at period end):			
Net property, plant and equipment	$ 340,889	$ 309,675	$ 404,842
Total assets	366,011	372,179	487,038

	Years Ended December 31,		
Total debt, including current portion	240,000	181,333	225,000
Net partners' capital (net parent investment)	117,528	157,361	215,195
Operating Data:			
West Coast Operations:			
Pipeline throughput (mbpd)(8)	166.3	158.0	162.8
Rocky Mountain Operations:			
Salt Lake City Core system throughput (mbpd)(8)(10)			70.0
Western Corridor system throughput (mbpd)(8)(10)			15.0
AREPI pipeline throughput (mbpd)(8)	39.4	41.1	45.6
Frontier pipeline throughput (mbpd)(8)(9)	37.4	40.5	44.4

(1) Includes our ownership of the Western Corridor system and Salt Lake City Core system assets since March 1, 2002.

(2) The above amounts are net of purchases of $158,293 and $314,903 for 2001 and 2002, respectively. The results for 2001 include six months of gathering, blending and marketing operations, the assets of which were purchased from EOTT Energy Partners on June 30, 2001.

(3) Provision for settlement expenses related to the AREPI pipeline rate case litigation.

(4) 2000 includes 12.5% of the net income of Frontier Pipeline Company. On December 17, 2001, Pacific Energy (Predecessor) acquired an additional 9.72% partnership interest in Frontier Pipeline Company. Therefore, 2001 includes 12.5% of the net income of Frontier Pipeline Company for the period January 1, 2001 through December 16, 2001 and 22.22% for the balance of the year. The data for 2002 includes 22.22% of the net income of Frontier Pipeline Company.

(5) EBITDA is defined as net income less interest income, plus interest expense and depreciation and amortization. The Partnership is not a taxable entity. EBITDA provides additional information for evaluating our ability to make the minimum quarterly distribution and is presented solely as a supplemental measure. You should not consider EBITDA as an alternative to net income, income before taxes, cash flows from operations, or any other measure of financial performance presented in accordance with accounting principles generally accepted in the United States. Our EBITDA may not be comparable to EBITDA or similarly titled measures of other entities as other entities may not calculate EBITDA in the same manner as we do.

(6) Net cash used in investing activities for 2001 includes a $10.6 million deposit made in connection with the acquisition of the Western Corridor system and Salt Lake City Core system assets and $8.6 million paid for an additional 9.7% partnership interest in Frontier Pipeline Company. Net cash used in investing activities for 2002 includes $95.0 million for certain assets acquired from BP on March 1, 2002.

(7) Net cash provided by financing activities for 2002 includes (i) proceeds of $167.7 million from the issuance of common units in connection with our initial public offering; (ii) proceeds of $225.0 million from the term loan facility; (iii) proceeds of $87.0 million of a note payable to bank in connection with the acquisition of BP assets; (iv) repayment of debt of $268.3 million; (v) distributions of $105.1 million to the General Partner at the time of our initial public offering; (vi) distributions prior to our initial public offering of $16.0 million to members; and (vii) offering and debt issue costs of $21.7 million.

(8) 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.

(9)

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

(10)
This amount represents throughput for the ten months ended December 31, 2002, as this system was acquired from BP on March 1, 2002.

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

The following discussion of the financial condition and results of operations of Pacific Energy Partners, L.P., the successor to Pacific Energy (Predecessor) (as defined below) should be read together with the consolidated financial statements and the notes thereto set forth elsewhere in this report. The discussion set forth in this section pertains to the consolidated financial position, results of operations and cash flows of, as well as equity investment in, the Partnership and its 100% ownership interest in Pacific Energy Group LLC ("PEG"), whose subsidiaries consist of (i) Pacific Pipeline System LLC ("PPS"), owner of Line 2000 and the Line 63 system, (ii) Pacific Marketing and Transportation LLC ("PMT"), owner of the PMT gathering and blending assets, (iii) Rocky Mountain Pipeline System LLC ("RMP"), owner of the Western Corridor system and the Salt Lake City Core system assets purchased from an affiliate of BP plc on March 1, 2002, (iv) Anschutz Ranch East Pipeline LLC ("AREPI"), owner of AREPI pipeline and (v) Ranch Pipeline LLC ("RPL"), the owner of a 22.22% partnership interest in Frontier Pipeline Company ("Frontier"). Prior to July 26, 2002, the financial data and results of operations for PPS, PMT, RMP, AREPI and RPL, are presented on a combined basis and constitute the Predecessor. Subsequent to July 26, 2002, the financial data and results of operations of PPS, PMT, RMP, AREPI and RPL are presented on a consolidated basis as successor to the Predecessor. This discussion does not include any financial data from the Edison Pipeline and Terminal Company ("EPTC") assets we expect to acquire from Southern California Edison ("SCE") in the second quarter of 2003.

Critical Accounting Policies

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

- 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 that cleanup costs are probable 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.

Overview

We are engaged in the business of gathering, blending, transporting, storing and distributing crude oil. We conduct our business through two regional operating units: West Coast operations and Rocky Mountain operations. Our West Coast operations consist primarily of transporting crude oil produced

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in the San Joaquin Valley and the California Outer Continental Shelf to refineries and terminal facilities in the Los Angeles Basin and Bakersfield through our two intrastate common carrier crude oil pipelines, Line 2000 and the Line 63 system. Our West Coast operations also include an intrastate proprietary crude oil gathering and blending system located in the San Joaquin Valley, through which we engage in the gathering, blending and marketing of crude oil that is generally delivered into our Line 63 system. Our Rocky Mountain operations consist of the Western Corridor system, the Salt Lake City Core system, AREPI pipeline and RPL's interest in Frontier pipeline.

We generate revenue primarily by charging a tariff for transporting crude oil on our pipelines. The amount of revenue we generate depends on the level of these tariff rates and the amount of throughput on our pipelines. The amount of throughput is dependent upon the availability of crude oil in the producing fields and the demand for the crude oil in the refining markets served by our pipelines. Our customers, or shippers, are primarily refiners that transport their crude oil on our pipelines for ultimate delivery to their refineries. Some of our customers are required under contracts with us to transport minimum volumes of crude oil annually.

The tariff rates are charged to the customer upon delivery of the crude oil to its ultimate delivery point. The tariff rates charged on Line 2000 and Line 63 are regulated by the California Public Utilities Commission ("CPUC"). Line 2000 has market-based tariff rates. Competition, as well as certain contractual limitations, determine the tariff rates we charge on Line 2000. Tariff rates on Line 63 are established using a cost-based methodology, which, among other things, allows for a regulated rate of return on the depreciated, historical cost of the assets. We also purchase crude oil produced in the San Joaquin Valley for subsequent blending, transportation and resale primarily in the Los Angeles Basin.

The tariff rates charged on AREPI pipeline and Frontier pipeline are regulated by the Federal Energy Regulatory Commission ("FERC") under a cost-based rate methodology. Pursuant to recent settlements of tariff rate case litigation before the FERC, AREPI and Frontier agreed to reduce certain local tariff rates in 2002 on AREPI pipeline and Frontier pipeline as well as their respective portions of the post-complaint rates under a joint tariff that had been filed by Express pipeline (which was subsequently cancelled). The FERC and the Wyoming Public Service Commission regulate tariffs on the Western Corridor and Salt Lake City Core systems on a cost-based methodology.

A substantial portion of the operating expenses we incur, including the cost of field and support personnel, maintenance, control systems, telecommunications, rights-of-way, insurance and depreciation, varies little with changes in throughput. Certain of our costs, however, do vary with throughput, the most material being the cost of fuel and power used to run the various pump stations along our pipelines.

The Partnership does not have any employees. All our personnel are employed by Pacific Energy GP, Inc., our general partner ("General Partner"). 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. In addition, Anschutz continues to provide certain services to us and all direct and reasonable costs incurred by Anschutz, on our behalf, are charged to us. Please read "Item 13 Certain Relationships and Related Transactions Other Related Party Transactions" below.

Construction and Acquisition History

Our business has been developed through new project development and various acquisitions, including:

- in 1983, participation in the construction of Frontier pipeline;

- in 1987, the construction of AREPI pipeline at a cost of approximately $6.6 million;

- in February 1999, the completion of the construction of Line 2000 at a cost of approximately $275.0 million;

- in May 1999, the acquisition of the Line 63 system from ARCO Pipe Line Company ("ARCO") in exchange for an interest in PPS, which held (and continues to hold) our Line 2000 and Line 63 system;

- in June 2001, the acquisition of ARCO's ownership interest in PPS, increasing our ownership interest thereof to 100%, for approximately $47.0 million;

- in June 2001, the acquisition of certain gathering and blending assets from EOTT Energy Partners for approximately $14.4 million;

in December 2001, the acquisition of an additional 9.72% partnership interest in Frontier from BP, increasing our ownership interest to 22.22% from 12.5%, for approximately $8.6 million;

in March 2002, the acquisition of BP's Western Corridor system and the Salt Lake City Core system assets, for approximately $106.0 million. Other than with respect to periods after March 2002, this acquisition is not included in our consolidated financial statements; and

in February 2002, the execution of an agreement to purchase the EPTC assets from SCE for approximately $158.2 million, plus upward adjustments. This acquisition is pending. We expect to complete this acquisition in the second quarter of 2003.

Results of Operations

The table below sets forth certain segment operating results by regional operating unit for the years ended December 31, 2000, 2001 and 2002:

	Year Ended December 31,		
	2000	**2001**	**2002**
		(in thousands)	
Segment Operating Income			
West Coast Operations:			
Pipeline transportation revenue:			
Unaffiliated customers	$ 63,157	$ 60,835	$ 62,054
Affiliates	3,324	246	2,339
Total pipeline transportation revenue(1)	66,481	61,081	64,393
Crude oil sales, net of purchases		9,028	22,158
Net revenue before operating expenses	66,481	70,109	86,551
Expenses:			
Operating	25,523	33,026	37,417
Transition costs		220	139
Depreciation and amortization	11,248	10,887	11,229
Total expenses	36,771	44,133	48,785
Operating income	$ 29,710	$ 25,976	$ 37,766
Operating Data:			
Pipeline throughput (mbpd)(2)	166.3	158.0	162.8
Rocky Mountain Operations:			
Pipeline transportation revenue:			
Unaffiliated customers	$ 3,762	$ 4,505	$ 37,635
Affiliates	1,176	650	325
Total pipeline transportation revenue	4,938	5,155	37,960

	Year Ended December 31,		
Expenses:			
Operating	1,465	1,356	16,926
Transition costs			2,495
Rate case litigation settlement		1,853	
Depreciation	625	481	4,690
Total expenses	2,090	3,690	24,111
Share of net income of Frontier	1,738	1,569	1,347
Operating income	$ 4,586	$ 3,034	$ 15,196
Operating Data:			
Salt Lake City Core system throughput (mbpd)(2)(4)			70.0
Western Corridor system throughput (mbpd)(2)(4)			15.0
AREPI pipeline throughput (mbpd)(2)	39.4	41.1	45.6
Frontier pipeline throughput (mbpd)(2)(3)	37.4	40.5	44.4
Income Statement Reconciliation			
Operating income from above:			
West Coast Operations	$ 29,710	$ 25,976	$ 37,766
Rocky Mountain Operations	4,586	3,034	15,196
Less: General and administrative(5)	2,672	4,134	8,622
Operating income	31,624	24,876	44,340
Other income	357	467	516
Interest income	474	320	385
Interest expense	(18,115)	(10,056)	(11,667)
Net income	$ 14,340	$ 15,607	$ 33,574

(1) The above amounts are net of purchases of $158,293 and $314,903 for 2001 and 2002, respectively.

(2) 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.

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

(4) This amount represents throughput for the ten months ended December 31, 2002, as this system was acquired from BP on March 1, 2002.

(5) General and administrative expenses are not allocated among the West Coast and Rocky Mountain operations.

Year ended December 31, 2002 Compared to Year Ended December 31, 2001

Net income. Consolidated net income totaled $33.6 million in 2002 compared to $15.6 million in 2001, an increase of $18.0 million, or 115%. This increase was due to the acquisition of the Western Corridor system and Salt Lake City Core system assets on March 1, 2002, higher volumes and tariffs on Line 2000 and the Line 63 system, and a full year of operation and improved results from our PMT assets (the assets were acquired on July 1, 2001).

Pipeline Transportation Revenue. Consolidated pipeline transportation revenue totaled $102.4 million in 2002 compared to $66.2 million in 2001, an increase of $36.2 million, or 55%. This increase was primarily due to our Rocky Mountain operations, where revenue increased by $32.8 million due to revenue generated by the Western Corridor system and the Salt Lake City Core system assets. In addition, pipeline transportation revenue from our West Coast operations increased by $3.4 million compared to 2001. The West Coast pipeline transportation revenue increase was due to the increase in long-haul throughput volumes of approximately 4,800 bpd, or 3%, and an increase in average tariff rates. The strong refinery demand for crude oil by the Los Angeles Basin refiners and the absence of any significant refinery or production outages in our delivery market account for the increased volumes compared to 2001. This increase in West Coast revenue in 2002 was partially offset by $2.9 million attributable to the elimination of pipeline transportation revenue that was previously charged to EOTT as a third party during the first six months of 2001.

Crude Oil Sales, net. On July 1, 2001, we acquired the PMT gathering and blending assets which generated net revenue before operating expenses in 2002 of $22.2 million on total sales of $337.1 million. PMT generated net revenue before operating expenses of $9.0 million on total sales of $167.3 million for the six months ended December 31, 2001. We consider this activity to be ancillary to our pipeline transportation operations.

Operating Expenses. Consolidated operating expenses totaled $54.3 million in 2002 compared to $34.4 million in 2001, an increase of $19.9 million, or 58%. This increase was related primarily to our Rocky Mountain operations where operating expenses increased by $15.5 million due to the acquisition of the Western Corridor system and the Salt Lake City Core system assets. Operating expenses for our West Coast operations increased by $4.4 million due primarily to field operating, blending and trucking expenses related to our PMT gathering and blending system.

General and Administrative Expense. Consolidated general and administrative ("G&A") expenses were $8.6 million in 2002 compared to $4.1 million in 2001, an increase of $4.5 million, or 110%. This increase was due in part to the acquisition of the Western Corridor system and the Salt Lake City Core system assets, and a full year of PMT reflected in operations. In addition, we incurred an additional $1 million in G&A expenses in 2002 as a result of the transition from a private company to a publicly traded company and to comply with new Securities and Exchange Commission "(SEC") and stock exchange regulations.

Depreciation and Amortization Expense. Consolidated depreciation and amortization expense was $15.9 million in 2002 compared to $11.4 million in 2001, an increase of $4.5 million, or 39%. The increase consists of $4.2 million related to the acquisition of the Western Corridor and the Salt Lake City core system assets.

Interest Expense. Interest expense was $11.7 million in 2002 compared to $10.1 million in 2001, an increase of $1.6 million, or 16%. This increase was due to an increase in the average daily debt balances, which were $235.5 million in 2002 as compared to $203.9 million in 2001. The interest rate on outstanding borrowings in 2002 averaged 5.0% compared to 4.7% in 2001.

Share of Net Income of Frontier. Our share of Frontier's net income was $1.3 million in 2002 compared to $1.6 million in 2001. This decrease was due to lower tariff revenue and payment of rate case settlement costs by Frontier, which were partially offset by the increase in our ownership interest from 12.5% to 22.22% in December 2001.

Year Ended December 31, 2001 Compared To Year Ended December 31, 2000

Net income. Consolidated net income totaled $15.6 million in 2001 compared to $14.3 million in 2000, an increase of $1.3 million, or 9%. This increase was due to the acquisition of the PMT gathering and blending assets from EOTT Energy Partners on July 1, 2001, partially offset by a decrease in pipeline transportation revenue.

Pipeline Transportation Revenue. Consolidated pipeline transportation revenue totaled $66.2 million in 2001 compared to $71.4 million in 2000, a decrease of $5.2 million, or 7%. This decrease was associated primarily with our West Coast operations, where revenue decreased by $5.4 million from 2000. Several factors contributed to this decrease including a decrease in average throughput volumes from 2000 to 2001 of approximately 8,300 bpd, or 5%. This decrease in throughput was primarily the result of three factors: (i) several planned and unplanned refinery outages in the Los Angeles Basin, most notably an outage due to a fire in April 2001 at a major Los Angeles Basin refinery; (ii) the curtailment of steam-flooding operations in the San Joaquin Valley due to the higher cost of natural gas (which is used to generate the steam), resulting in a steeper decline in San Joaquin Valley crude oil production; and (iii) the temporary shutdown of a California Outer Continental Shelf oil field from September 15 through December 31, 2001 to repair a defect in an undersea pipeline. Also contributing to the decline was the elimination of approximately $3.2 million of pipeline transportation revenue that were previously charged to EOTT Energy Partners as a third-party shipper during 2000 and for the first half of 2001, prior to our acquisition of the PMT assets. The various pipeline transportation revenue declines were offset, in part, by the positive effects of tariff rate increases, which added approximately $2.1 million of revenue.

Crude Oil Sales, Net of Purchases. On July 1, 2001, we acquired the PMT gathering and blending assets, which generated net revenue before operating expenses for the six-month period ended December 31, 2001 of $9.0 million on total sales of $167.3 million. We consider this activity to be ancillary to our pipeline transportation operations.

Operating Expenses. Consolidated operating expenses totaled $34.4 million in 2001 compared to $27.0 million in 2000, an increase of $7.4 million, or 27%. This increase was related primarily to our West Coast operations where operating expenses increased by $7.5 million principally due to two factors: (i) the cost to provide power to the pipeline pumping stations increased by approximately $2.8 million as a result of the energy shortages in California and related power rate increases implemented in January and March of 2001, and (ii) operating expenses for the second half of 2001 include field operating, blending and trucking expenses of $5.7 million related to our PMT gathering and blending system.

General and Administrative Expense. Consolidated general and administrative expenses were $4.1 million in 2001 compared to $2.7 million in 2000, an increase of $1.4 million, or 52%. Substantially all the increase was associated with our West Coast operations, for corporate development expenses and expenses relating to our gathering and blending operations.

Rate Case Litigation Settlement. The 2001 settlement costs related to the AREPI pipeline FERC rate case litigation. In March 2002, we reached a settlement with all complainants and all issues in this litigation have been resolved. Pursuant to the settlement agreement we reduced certain of our FERC tariff rates charged on AREPI pipeline and paid a cash settlement. During 2001, we incurred various legal and consulting expenses associated with this litigation totaling $0.3 million. At December 31, 2001, we accrued an estimate of $1.5 million which represented the remaining cost of this settlement.

Depreciation and Amortization Expense. Consolidated depreciation and amortization expense was $11.4 million in 2001 compared to $11.9 million in 2000, a decrease of $0.5 million, or 4%. This decrease primarily consists of $0.7 million attributable to the negative goodwill of $40.6 million resulting from the acquisition of ARCO's ownership interest in PPS, partially offset by additional depreciation primarily relating to the acquisition of the PMT assets.

Interest Expense. Interest expense was $10.1 million in 2001 compared to $18.1 million in 2000, a decrease of $8.0 million, or 44%. This decrease was associated with lower borrowing rates during 2001 and a reduction in our outstanding debt balance. The interest rate on outstanding borrowings during 2001 averaged 4.7% compared to 7.5% during 2000. Total outstanding debt decreased by $63.6 million on June 7, 2001 due to the repayment of an outstanding note payable to ARCO.

Share of Net Income of Frontier. Our share of Frontier's net income was $1.6 million in 2001 compared to $1.7 million in 2000, due to higher maintenance costs.

Liquidity and Capital Resources

Historically, we have satisfied our working capital requirements and funded our capital expenditures with cash generated from operations and affiliated and third-party borrowings. We believe that cash generated from operations and our borrowing capacity will be sufficient to meet our working capital requirements, anticipated capital expenditures and scheduled debt payments for at least the next several years. We expect to fund any future acquisitions with the proceeds of borrowings under our revolving credit facility and the issuance of additional units. Our ability to satisfy our debt service obligations, fund planned capital expenditures, make acquisitions 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 we transport, which could be affected by a decrease in the volume of crude oil produced from the oil fields or processed by the refineries served by our

pipelines. These factors, which are affected by prevailing economic conditions in the crude oil industry and financial, business and other factors, some of which are beyond our control, could significantly impact future results.

Cash Flows and Capital Expenditures

Net cash provided by operating activities was $45.8 million in 2002 compared to $26.4 million in 2001, an increase of $19.4 million, or 73%. This increase was primarily associated with the increase in net income and changes in certain working capital items related to the acquisition of the PMT, Western Corridor system and Salt Lake City Core system assets, as well as increased net income from PPS.

Net cash used in investing activities in 2002 and 2001 was $101.3 million and $37.2 million, respectively. This increase was primarily associated with the acquisition of the Western Corridor system and Salt Lake City Core system assets on March 1, 2002. Capital expenditures were $6.0 million in 2002, of which $2.6 million related to maintenance projects, $2.1 million related to the transition of RMP assets, and $1.3 million related to expansion. Capital expenditures were $5.8 million in 2001, of which $3.4 million related to maintenance and $2.4 million related to expansion.

Net cash from financing activities was $69.9 million in 2002 and $8.0 million in 2001. Prior to our initial public offering in July 2002, distributions to members by PEG were $16.0 million and $22.8 million in 2002 and 2001, respectively. Capital contributed by members to PEG prior to our initial public offering was $8.8 million and $90.6 million in 2002 and 2001, respectively. In March 2002, net proceeds of $87.0 million from notes payable were used to fund the acquisition of the Western Corridor system and Salt Lake City Core system assets. In connection with our initial public offering, proceeds of $167.7 million from the issuance of common units were used to pay underwriting discounts, professional fees and other offering costs of $16.4 million and to repay $151.3 million in debt. Proceeds of $225.0 million from the term loan facility were used to pay debt issuance costs of $5.3 million, repay $114.6 million in debt and to fund distributions of $105.1 million to the General Partner. Distributions to the limited partner interests subsequent to our initial public offering were $7.0 million in 2002.

Net cash provided by operating activities was $26.4 million in 2001 compared to $26.3 million in 2000, an increase of $0.1 million, or 1%. This increase was primarily associated with the increase in net income and changes in certain working capital items.

Net cash used in investing activities in 2001 and 2000 was $37.2 million and $3.5 million, respectively. Investing activity in 2001 consisted of: (i) the acquisition of the PMT gathering and blending assets from EOTT Energy Partners for $12.1 million; (ii) the acquisition of an additional 9.72% partnership interest in Frontier Pipeline Company from BP for $8.6 million; and (iii) the $10.7 million deposit for the acquisition of the Western Corridor system and Salt Lake City Core system assets from BP which closed in March 2002. Capital expenditures were $5.8 million in 2001 and $3.5 million in 2000.

Net cash from financing activities consisted of a net source of cash of $8.0 million in 2001 and a net use of cash of $17.6 million in 2000. Distributions to members were $22.8 million in 2001 and $19.6 million in 2000. Capital contributed by members was $90.6 million in 2001 and $0.9 million in 2000. The $90.6 million of capital contributions in 2001 consist of: (i) a $63.6 million contribution by ARCO which was used to repay the ARCO debt; and (ii) approximately $27.0 million of contributions by Anschutz in connection with the PMT asset acquisition, the deposit for the Western Corridor and Salt Lake City Core system assets, and other miscellaneous items.

Capital Requirements

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

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

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

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

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

	Year Ended December 31,		
	2000	**2001**	**2002**

	Year Ended December 31,		
	(in thousands)		
Maintenance capital expenditures	$ 1,662	$ 3,381	$ 2,649
Transitional capital expenditures			2,061
Expansion capital expenditures	1,825	2,433	1,290
Total	$ 3,487	$ 5,814	$ 6,000

We have budgeted total maintenance capital expenditures of $2.7 million and expansion capital expenditures of $0.4 million for 2003. These expenditures exclude any EPTC related capital expenditures.

We expect to complete the acquisition of the EPTC assets in the second quarter of 2003. The purchase price for the EPTC assets is $158.2 million, plus potential increases for certain pre-closing capital expenditures and prepayments made by the seller relating to the purchased assets, and the value of displacement oil and warehouse inventory. We expect that these adjustments will be in the range of $5.0 million to $10.0 million. We intend to finance this acquisition initially from borrowings under our revolving credit facility, followed by the issuance of additional units, including common units, to repay a portion of the borrowings under our revolving credit facility.

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 future minimum payments, as of December 31, 2002, under our right-of-way agreements are presented below and reflect our commitment for the next 15 years assuming the current right-of-way agreements will be renewed during the period. The annual amounts payable under certain of the right-of-way agreements are subject to fair market and inflation adjustments.

	ROW Payments
	(in thousands)
Years ending December 31:	
2003	$ 2,864
2004	2,864
2005	2,861
2006	2,861
2007	2,861
Thereafter	12,914
Total	$ 27,225

Right-of-way payments, which are included in operating expenses, were $5.2 million, $5.2 million and $3.3 million in 2000, 2001 and 2002, respectively.

Credit Facilities

In connection with the completion of our initial public offering of common units, PEG entered into a new $425.0 million credit agreement with a syndicate of financial institutions led by Fleet National Bank, that provides for a five-year $200.0 million senior secured revolving credit facility and a seven-year $225.0 million senior secured term loan facility. On July 26, 2002, PEG borrowed $225.0 million under the term loan facility.

The revolving credit facility is available for general partnership purposes, including working capital, letters of credit and distributions to unitholders and to finance future acquisitions, including the pending acquisition of the EPTC assets. The revolving credit facility has a borrowing sublimit of $45.0 million for working capital, letters of credit and distributions to unitholders. The revolving credit facility is currently undrawn except for letters of credit totaling $6.5 million at December 31, 2002.

The revolving credit facility matures on July 26, 2007, at which time it will terminate and all outstanding amounts will be due and payable. We are required to amortize amounts outstanding under the term loan facility on a quarterly basis at 1% per annum beginning in 2005, with the first quarterly payment due September 2005. A 97% balloon payment will be due at maturity in July 2009. The payments due on the term loan facility are presented below:

	Payments (in thousands)
Year ending December 31,	
2003	$
2004	
2005	1,125
2006	2,250
2007	2,250
Thereafter	219,375
Total	$ 225,000

We may prepay all loans under the revolving credit facility at any time, and all loans under the term loan facility any time following the first anniversary of the closing of the facilities, without premium or penalty. Prepayment of the term loan facility during the first year will result in a 1% premium. Except as otherwise subsequently agreed by certain of the lenders, mandatory prepayments and commitment reductions will generally include the net cash proceeds of asset sales not sold in the ordinary course of business and the net proceeds of new senior secured debt offerings, subject to certain exceptions.

The facilities are guaranteed by the Partnership and certain of PEG's subsidiaries. The facilities are fully recourse to PEG and the guarantors, but non-recourse to our General Partner. Obligations under the facilities are or will be secured by pledges of membership interests in and assets of PEG's subsidiaries, subject to certain limited exceptions.

Indebtedness under the facilities bear interest at the Partnership's option, at either (i) the base rate, which is equal to the higher of the prime rate as announced by Fleet National Bank or the Federal Funds rate plus 0.50% (each plus an applicable margin ranging from 0% to 0.50% for the revolving credit facility and ranging from 0.50% to 0.75% for the term loan facility) or (ii) LIBOR plus an applicable margin for the revolving credit facility ranging from 1.25% to 2.50% and the term loan facility ranging from 2.50% to 2.75%. The applicable margins are subject to change based on the credit rating of the facilities or, if they are not rated, the credit rating of PEG. After the purchase of the EPTC assets, the applicable margin will increase by a margin which ranges from 0.375% to 0.625% and will remain at that level for 270 days after the purchase or until we successfully conclude an equity offering that reduces certain ratios to specified levels, whichever is earlier. PEG will incur a per annum commitment fee margin which ranges from 0.25% to 0.50% on the unused portion of the revolving credit facility. The credit agreement prevents PEG from declaring dividends or distributions if any event of default, as defined in the credit agreement, occurs or would result from such declaration. In addition, the credit agreement contains covenants limiting the ability of PEG and certain of its subsidiaries to, among other things:

- incur or guarantee indebtedness;
- change ownership or structure, including consolidations, liquidations and dissolutions;

- repurchase or redeem units;
- make certain negative pledges and grant certain liens;
- sell, transfer, assign or convey assets;
- make certain loans and investments;
- enter into a new line of business;
- transact business with affiliates;
- enter into agreements restricting loans or distributions made by PEG's subsidiaries to us or PEG; or
- participate in certain hedging and derivative activities.

The credit agreement also contains covenants requiring PEG, including certain of its subsidiaries, to maintain:

- a ratio of maximum total funded debt to consolidated EBITDA (each as defined in the credit agreement) of up to 4.25:1, stepping down to 4.00:1 at December 31, 2003; provided that this ratio shall remain at 4.25:1 so long as we maintain an investment grade rating from either S&P or Moody's. For 270 days following the closing of the acquisitions of the EPTC assets or until we successfully conclude an equity offering that reduces certain ratios to specified levels, whichever is earlier, this ratio will increase to 5.25:1. This ratio will be tested quarterly on a rolling four-quarter basis and upon each incurrence of debt;
- a maximum of debt to total capital of 70%; and
- a minimum interest coverage ratio (as defined in the credit agreement) of 3.00:1 to be tested quarterly on a trailing four-quarter basis. For the four quarters following the closing of the acquisitions of the EPTC assets, this ratio will decrease to 2.50:1.

Each of the following is an event of default under the facilities:

- failure to pay any principal, interest, fees, expenses or other amounts;
- failure to observe any agreement, security instrument, obligation or covenant included in the credit agreement or in any guaranty, subject to various cure provisions;
- judgments against us, our General Partner or any of our subsidiaries in excess of certain allowances;
- default under other indebtedness of PEG and the guarantors of the facilities' indebtedness in excess of a threshold amount;
- certain ERISA events involving us or our subsidiaries;

bankruptcy or insolvency events involving us, our General Partner or our subsidiaries;

failure of any representation or warranty to be materially true and correct; and

a change of control (as defined in the credit agreement).

In August and September 2002, PEG entered into three interest rate swap agreements pursuant to which it executed five interest rate swap transactions that mature in 2009, totaling $140.0 million, and two interest rate swap transactions that mature in 2007, totaling $30.0 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 the term loan facility. The average swap rate on this $170.0 million of debt is approximately 4.25%, resulting in an all-in interest rate on the $170.0 million of approximately 7.00% (including the current applicable margin of 2.75%).

As of December 31, 2002, interest rates, as measured by market quotations for the future periods covered by the interest rate swap agreements, had declined as compared to August and September 2002, when PEG entered into these interest rate swap agreements. This decline resulted in an unrealized loss of $7.4 million on the aggregate interest rate hedge, which is recorded as a liability at December 31, 2002. The $7.4 million liability is shown on the consolidated balance sheet in two components, a current liability of $4.8 million, and a long term liability of $2.6 million. The unrealized loss is shown in "other comprehensive income," a component of partners' capital, and not in the consolidated income statement. Should interest rates remain unchanged from the December 31, 2002 market quotations for these future periods, actual losses realized on the interest rate swap agreements in each of the future periods would be offset by the benefit of lower floating rates in those periods, such that total net interest expense on the $170.0 million of hedged debt would be fixed at the all-in interest rate of 7.00%.

Impact of Inflation

Inflation in the United States 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, 2000, 2001 or 2002.

Environmental Matters

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

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

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

Recent Accounting Pronouncements

In December 2002, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 148 ("SFAS No. 148"), "Accounting for Stock-Based Compensation Transition and Disclosure." SFAS No. 148 amends Statement of Financial Accounting Standards No. 123 ("SFAS No. 123"), "Accounting for Stock-Based Compensation," to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. Furthermore, SFAS No. 148 amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. SFAS No. 148 is effective for fiscal years ending after December 15, 2002. We have included the required disclosures in note 10 of our consolidated financial statements.

In January 2003, the FASB issued FASB Interpretation No. 46 ("FIN 46"), "Consolidation of Variable Interest Entities." This interpretation clarifies the application of Accounting Research Bulletin No. 51 ("ARB 51"), "Consolidated Financial Statements," and requires companies to evaluate variable interest entities for specific characteristics to determine whether additional consolidation and disclosure requirements apply. This interpretation is immediately applicable for variable interest entities created after January 31, 2003, and applies to fiscal periods beginning after June 15, 2003 for variable interest entities acquired prior to February 1, 2003. We do not expect that the adoption of this interpretation will have any impact on our financial position or results of operations.

In November 2002, the FASB issued FASB Interpretation No. 45 ("FIN 45"), "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." This interpretation clarifies the requirements of a guarantor in accounting for and disclosing certain guarantees issued and outstanding. This interpretation is effective for fiscal years ending after December 15, 2002. The adoption of this interpretation did not have any impact on our financial position or results of operations in 2002.

In July 2002, the FASB issued Statement of Financial Accounting Standards No. 146 ("SFAS No. 146"), "Accounting for Costs Associated with Exit or Disposal Activities." SFAS No. 146 nullifies Emerging Issues Task Force ("EITF") Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." It requires that a liability be recognized for those costs only when the liability is incurred, that is, when it meets the definition of a liability in the FASB's conceptual framework. SFAS No. 146 also establishes fair value as the objective for initial measurement of liabilities related to exit or disposal activities. SFAS No. 146 is effective for exit or disposal activities that are initiated after December 31, 2002, with earlier adoption encouraged. We do not expect that the adoption of this standard will have any impact on our financial position or results of operations.

In April 2002, the FASB issued Statement of Financial Accounting Standards No. 145, ("SFAS No. 145"), "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections." The rescission of FASB Statement No. 4, "Reporting Gains and Losses from Extinguishment of Debt," ("Statement No. 4") and FASB Statement No. 64, "Extinguishments of Debt Made to Satisfy Sinking-Fund Requirements," which amended Statement No. 4, will affect income statement classification of gains and losses from extinguishment of debt. Upon adoption, enterprises must reclassify prior period items that do not meet the extraordinary item classification criteria in Accounting Principles Bulletin No. 30, "Reporting the Results of Operations." The provisions of SFAS No. 145 related to the rescission of Statement No. 4 are applicable in fiscal years beginning after May 15, 2002, with early application encouraged. The provisions of SFAS No. 145 related to FASB Statement No. 13, "Accounting for Leases," are effective for transactions occurring after May 15, 2002, with early application encouraged. All other provisions of SFAS No. 145 are effective for financial statements issued on or after May 15, 2002, with early application encouraged. We do not expect that the adoption of SFAS No. 145 will have any impact on our financial position or results from operations.

In August 2001, the FASB issued Statement of Financial Accounting Standards No. 143 ("SFAS No. 143"), "Accounting for Asset Retirement Obligations." This statement requires entities to record the fair value of a liability for legal obligations associated with the retirement obligations of tangible long-lived assets in the period in which it is incurred. When the liability is initially recorded, the entity increases the carrying amount of the related long-lived asset. Over time, accretion of the liability is recognized each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. The standard is effective for fiscal years beginning after June 15, 2002, with earlier adoption encouraged.

Effective January 1, 2003, we adopted SFAS No. 143, as required. Determination of the amounts to be recognized upon adoption is based upon numerous estimates and assumptions, including future retirement costs, future inflation rates and the credit-adjusted risk-free interest rate. A substantial portion of our assets have obligations to perform removal and/or remediation activities when the asset is retired. However, the fair value of the asset retirement obligation cannot be reasonably estimated, as the retirement dates are indeterminate. We will record such asset retirement obligation in the period in which we determine the retirement dates. The cumulative effect of adopting this standard did not have a material impact on our financial position, results of operations or cash flows.

Risks Inherent in Our Business

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

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

- the volume of crude oil we transport through our pipelines;
- the tariff rates we charge on our pipelines;

- our blending and marketing margins;
- the level of our operating costs, including payments to our General Partner;
- the level of competition from other pipelines; and
- prevailing economic conditions.

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

- the level of capital expenditures we make;
- the restrictions contained in our debt agreements and our debt service requirements;
- fluctuations in our working capital needs;
- the cost of acquisitions, if any;
- our ability to borrow under our working capital facility to make distributions; and
- the amount, if any, of cash reserves established by our General Partner, in its discretion.

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

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

Any significant reduction in the volume of crude oil processed at the refineries we serve could reduce the volume of crude oil we transport on our pipelines, or throughput, 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.

The 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:

- 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 proceedings or other litigation 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. For example, construction of a refined products pipeline system able to deliver products from refiners on the Texas Gulf Coast to Salt Lake City via a series of connected pipeline segments has been discussed by various companies for a number of years. If built, such a pipeline would compete with our Rocky Mountain operations.

The refineries we serve may not be able to secure adequate supplies of crude oil. For example, Line 2000 and Line 63 primarily serve refineries in the Los Angeles Basin. These refineries compete with refineries in the San Francisco Bay and central California areas for adequate 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.

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

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

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

A decrease in the price of crude oil, on either a temporary or permanent basis, may also affect the total volume of crude oil produced from the fields served by our pipelines. If crude oil prices were to decline significantly, as they did in 1998 and other periods in the past, production from 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 the fields served by our pipelines and therefore reduce production.

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 one. As a result, we or third-party shippers on our pipeline systems may experience difficulty acquiring crude oil at the wellhead in areas where there are existing relationships between producers and other gatherers and purchasers of crude oil.

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

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

New competing pipeline systems could also be built that 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.

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 rely primarily on the revenue generated from our transportation and storage businesses. Due to our lack of asset diversification, an adverse development in one of these businesses would have a significantly greater impact on our financial condition and results of operations than if we operated more diverse assets.

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

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

In recent decisions involving unrelated oil pipeline limited partnerships, the FERC has ruled that these partnerships may not claim an income tax allowance for income allocable to non-corporate limited partners. A shipper could rely on these decisions and claim that, because of the creation of the partnership, the income tax allowance used to calculate our interstate tariff rates should be reduced. If the FERC were to disallow the inclusion of all or part of the income tax allowance, it may be more difficult to justify some of our tariff rates. Any reduction in our tariff rates would most likely result in lower revenue and cash flows and may reduce our ability to make cash distributions to our unitholders.

Intrastate Pipelines. The majority of our intrastate pipeline 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.

For a discussion of challenges to our rates, please read "Item 3 Legal Proceedings."

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

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

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

In our gathering, blending 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 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 operations are subject to federal, state and local laws and regulations, including those relating to environmental protection and operations and safety, that could require us to make substantial expenditures.

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

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

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

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 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. There is certain coverage that we have elected not to purchase, such as business interruption insurance. 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. In some instances, certain insurance 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. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our financial position.

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

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

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

In 2002, the following customers represented greater than 10% of net revenue for our West Coast operations: ChevronTexaco; ExxonMobil Refining & Supply Company; Shell Trading Company; Tosco Refining Company and Valero Marketing and Supply Company. In addition, the following customers represented greater than 10% of net revenue for our Rocky Mountain operations: BP, ChevronTexaco; ConocoPhillips and Tesoro. The loss of any of these customers, a decline in their credit worthiness or a substantial reduction in their shipments on our pipelines, could adversely affect our results of operations and cash flows and our ability to make distributions to unitholders.

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

Our ability to grow will depend principally on our ability to complete attractive acquisitions. We may be unable to identify attractive acquisition candidates or to complete acquisitions 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 limitations on our ability to access new sources of capital may impair our ability to make acquisitions. If we are able to access new sources of capital, but only at more expensive rates, our ability to make accretive acquisitions will be limited. Our ability to maintain our capital structure may impact the market value of our common units.

Our acquisition strategy involves risks that may adversely affect our business.

Any acquisition involves potential risks, including:

- a significant increase in our indebtedness and working capital requirements;
- the inability to timely and effectively integrate the operations of recently acquired businesses or assets;
- the incurrence of substantial unforeseen environmental and other liabilities arising out of the acquired businesses or assets, including liabilities arising from the operation of the acquired businesses or assets prior to our acquisition;
- customer or key employee loss from the acquired businesses; and
- the diversion of management's attention from other business concerns.

Any of these factors could adversely affect our ability to achieve anticipated levels of cash flows from our acquisitions, realize other anticipated benefits and our ability to make distributions to unitholders.

We may be unable to complete the acquisition of the EPTC assets.

Completion of our acquisition of the EPTC assets is subject to the satisfaction of a number of conditions, including approval by the CPUC and other governmental authorities. There were three protests filed to our application seeking CPUC approval. Please read "Items 1 and 2 Business and Properties Pending EPTC Asset Acquisition" above. The acquisition agreement may be terminated in the event of uncured material breaches or defaults by a party, or if the CPUC disapproves the transaction or fails to render its approval before July 1, 2003, or by either party if the transaction has not been completed for failure of closing conditions by July 1, 2003. Moreover, some of the assets that we expect to acquire may ultimately not be acquired if necessary third-party consents cannot be obtained or if certain casualty events damage or destroy those assets. Accordingly, we cannot assure you that we will ultimately acquire the EPTC assets in the second quarter of 2003 or at all.

We do not have any commitment for the financing necessary to purchase the EPTC assets. The purchase price of these assets is $158.2 million, subject to upward adjustment. We anticipate financing this acquisition with a combination of borrowings under our revolving credit facility and the issuance of additional units, including common units. Our ability to borrow under our revolving credit facility may be limited by our debt levels or by contractual restrictions in our credit agreement or other agreements. Our ability to issue additional units, including common units, may be limited by capital market conditions and our ability to sell additional units. If we are unable to raise the funds necessary to pay the purchase price, we will be unable to consummate the acquisition of the EPTC assets and, as a result, may be in breach of our obligations under the acquisition agreement, which are not excused if we are unable to obtain financing.

The EPTC assets generate revenue primarily through the leasing of storage tank capacity. Lease rates for storage tanks are negotiated with each individual customer, resulting in private contracts with terms varying from approximately one month to two years, with the majority including automatic renewal provisions. The CPUC may not allow us to continue to use this approach. If we are unable to lease storage capacity on an arm's-length basis, our revenue and cash flows may be adversely affected, which could adversely affect our ability to make distributions to unitholders.

Our debt levels or restrictions in our debt agreements may prevent us from engaging in some beneficial transactions or paying distributions if we are in default.

At December 31, 2002, our total outstanding long-term indebtedness was $225.0 million, consisting entirely of the principal amount of our senior secured term loan. Our payment of principal and interest

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on this indebtedness will reduce the cash available for distribution on our units. We are prohibited by our credit agreement from making cash distributions during an event of default or if the payment of a distribution would cause an event of default. Various limitations in our credit agreement may reduce our ability to incur additional debt or to engage in some transactions and therefore to make acquisitions or pursue other business opportunities. Any subsequent refinancing of our current debt or any new debt could have similar or greater restrictions.

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 affecting 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%, distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to our unitholders. Because a tax would be imposed upon 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.

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. 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 affecting 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 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. 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 have registered as a tax shelter. This may increase the risk of an IRS audit of us or our unitholders.

We are registered as a tax shelter with the Secretary of the Treasury. Our tax shelter registration number is 02212000004. The IRS requires that some types of entities, including some partnerships, register as tax shelters in response to the perception that they claim tax benefits that the IRS may believe to be unwarranted. As a result, we may be audited by the IRS and tax adjustments could be made. Any unitholder owning less than a 1% profit interest in us has very limited rights to participate in the income tax audit process. Further, any adjustments in our tax returns will lead to adjustments, and may lead to audits of the tax returns of individual unitholders.

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 audit 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 may be subject to other taxes, including foreign, 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 may be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, unitholders may be subject to penalties for failure to comply with those requirements. We own assets and do business in California, Montana, Wyoming, Colorado and Utah. 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, foreign, state and local tax returns that may be required of such unitholder.

ITEM 7A. Quantitative and Qualitative Disclosures about Market Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. The principal market risks to which we are exposed are interest rate risk and crude oil price risk. Debt we incur under our credit facilities will bear variable interest at either the applicable base rate or a rate based on LIBOR. We have used and will continue to use certain derivative instruments to hedge our exposure to variable interest rates.

Although we generally do not own the crude oil that we transport in our pipelines, we purchase some crude oil in the San Joaquin Valley for subsequent blending, transportation and resale primarily in the Los Angeles Basin. We use, on a limited basis, certain derivative instruments (principally futures and options) to hedge our exposure to market price volatility related to our sales of crude oil. We do not enter into speculative derivative transactions. The derivative instruments are included in other assets in the accompanying balance sheets. Changes in the fair value of our derivatives are recognized in net income. In 2002, operating expenses include $0.4 million related to changes in the fair value of our derivative instruments for marketing activities and pipeline transportation revenue is net of $0.2 million related to changes in the fair value of our derivative instruments for pipeline loss allowance inventory.

In August and September 2002, PEG entered into three interest rate swap agreements pursuant to which it executed five interest rate swap transactions that mature in 2009, totaling $140.0 million, and two interest rate swap transactions that mature in 2007, totaling $30.0 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 the term loan facility. The average swap rate on this $170.0 million of debt is approximately 4.25%, resulting in an all-in interest rate on the $170.0 million of approximately 7.00% (including the current applicable margin of 2.75%).

As of December 31, 2002, interest rates, as measured by market quotations for the future periods covered by the interest rate swap agreements, had declined as compared to August and September 2002, when PEG entered into these interest rate swap agreements. This decline resulted in an unrealized loss of $7.4 million on the aggregate interest rate hedge, which is recorded as a liability at December 31, 2002. The $7.4 million liability is shown on the consolidated balance sheet in two components, a current liability of $4.8 million, and a long term liability of $2.6 million. The unrealized loss is shown in "other comprehensive income," a component of partners' capital, and not in the consolidated income statement. Should interest rates remain unchanged from the December 31, 2002 market quotations for these future periods, actual losses realized on the interest rate swap agreements in each of the future periods would be offset by the benefit of lower floating rates in those periods, such that total net interest expense on the $170.0 million of hedged debt would be fixed at the all-in interest rate of 7.00%. Accordingly, we are not subject to interest rate fluctuations on this portion of our term loan facility.

We are subject to risks resulting from interest rate fluctuations as interest on the remaining $55.0 million outstanding under our term loan facility is based on variable rates. If the LIBOR rate were to increase 1.0% in 2003 as compared to the rate at December 31, 2002, our interest expense for 2003 would increase $0.6 million based on the $55.0 million outstanding on our term loan facility at December 31, 2002, which has not been hedged.

ITEM 8. Financial Statements and Supplementary Data

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

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

None.

ITEM 10. Directors and Executive Officers of Pacific Energy Partners, L.P.

The following table shows information for the directors and executive officers of Pacific Energy GP, Inc. Executive officers and directors are elected for one-year terms.

Name	Age	Position with the General Partner
Douglas L. Polson	61	Chairman of the Board of Directors
Philip F. Anschutz	63	Director
Craig D. Slater	45	Director
Clifford P. Hickey	43	Director
David L. Lemmon	60	Director
Jim E. Shamas	68	Director

Name	Age	Position with the General Partner
Robert F. Starzel	62	Director
Irvin Toole, Jr.	61	President, Chief Executive Officer and Director
David E. Wright	58	Executive Vice President, Corporate Development and Marketing
Gerald A. Tywoniuk	41	Senior Vice President, Chief Financial Officer and Treasurer
Arthur G. Diefenbach	52	Vice President, Operations and Technical Services West Coast
Kevin R. Lee	34	Vice President, Crude Oil Marketing
Jesse G. Metcalf	52	Vice President, Operations and Technical Services Rocky Mountains
Lynn T. Wood	51	Vice President, General Counsel and Secretary
Gary L. Zollinger	54	Vice President, Marketing and Business Development Rocky Mountains
John D. Cook	56	Controller

Douglas L. Polson was elected Chairman of the Board of Directors in December 2001. He has been Chairman of the Board of Directors of Pacific Energy Group LLC since August 2001 and Chairman of the Members Committee of Pacific Pipeline System LLC since July 1999. 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.

Philip F. Anschutz was elected to the Board of Directors in December 2001. Mr. Anschutz has served as the Chairman of the Board of Directors of The Anschutz Corporation, which he founded in 1965, and Anschutz Company, its parent, for more than five years. Anschutz Company and The Anschutz Corporation are through their subsidiaries and affiliates engaged principally in telecommunications and media, natural resources, transportation, real estate, farming and ranching, sports and entertainment. He has been the non-executive Chairman of the Board of Directors of Regal Entertainment Group since May 2002 and a director of Qwest Communications International, Inc. since February 1997. He has been Non-Executive Vice Chairman of Union Pacific Corporation since 1996.

Craig D. Slater was elected to the Board of Directors in December 2001. He has served as a director of Pacific Energy Group LLC since August 2001 and as a representative on the Members Committee of Pacific Pipeline System LLC from July 1999 to August 2001. Mr. Slater has served as

President of Anschutz Investment Company since 1997 and as Executive Vice President of Anschutz Company since April 1999 and The Anschutz Corporation since May 1999. Mr. Slater served as Vice President of Acquisitions and Investments of both The Anschutz Corporation and Anschutz Company from August 1995 until May and April 1999, respectively. Anschutz Investment Company, a subsidiary of The Anschutz Corporation, engages in investment and acquisition activities for the Anschutz group of companies. He currently serves on the boards of directors of Regal Entertainment Group, Qwest Communications International, Inc. and Forest Oil Corporation.

Clifford P. Hickey was elected to the Board of Directors in March 2002. He has served as Managing Director of Anschutz Investment Company since June 2002. From July 1999 to May 2002 he served as Vice President of Anschutz Investment Company. From July 1998 to June 1999 he served as a Director in the Energy Group of Prudential Securities. From January 1993 through June 1998, he served as a Vice President of Enron Capital and Trade Resources.

David L. Lemmon was elected to the Board of Directors in April 2002. Mr. Lemmon has served as President and Chief Executive Officer of Colonial Pipeline Company since November 1997 and as a director since 1990. 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.

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 August 2001. 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.

Robert F. Starzel was elected to the Board of Directors in March 2002. Mr. Starzel has been the Senior Representative of the Chairman of the Union Pacific Corporation since September 2000. Mr. Starzel served as Senior Vice President of Union Pacific Corporation from April 1998 to September 2000 and as Vice President, Western Region of Union Pacific Railroad Company from September 1996 to April 1998. Mr. Starzel currently serves as a director of Regal Entertainment Group.

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, Chief Executive Officer and a representative on the Members Committee of Pacific Pipeline System LLC since July 1999 and President and Chief Executive Officer of its predecessor since June 1998. Mr. Toole joined Pacific Energy Group 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 and Marketing in December 2001 and served as director from December 2001 to June 2002. He has been Executive Vice President, Corporate Development and Marketing and director of Pacific Energy Group LLC since August 2001 and Executive Vice President Corporate Development and Marketing of Pacific Pipeline System LLC since June 2001. Mr. Wright joined Pacific Energy Group LLC in June 2001 after having served as Vice President, Distribution West of Tosco Refining Company from March 1997 to June 2001. From October 1995 to March 1997, Mr. Wright served as Vice President, Pipelines for GATX Terminals Corporation.

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

Arthur G. Diefenbach was elected Vice President, Operations and Technical Services West Coast in March 2002. 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 from August 1998 to July 1999 and as Superintendent, Operations of ARCO from January 1990 to August 1998.

Kevin R. Lee was elected Vice President, Crude Oil Marketing in March 2002. He has served as Vice President, Crude Oil Marketing for Pacific Marketing and Transportation LLC since July 2001. Prior to joining Pacific Marketing and Transportation LLC in July 2001, Mr. Lee served as Director, West Coast Crude Oil from November 1997 to June 2001 and as Manager, Crude Oil Blending and Supply from January 1995 to November 1997 for EOTT Energy Operating Partnership.

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 from 1987 to 2000. From 1982 to 1987, Mr. Metcalf served as Field Supervisor, Exploration and Production for The Anschutz Corporation.

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 PPS and, after their formation, PEG and the Partnership.

Gary L. Zollinger was elected Vice President, Marketing and Business Development Rocky Mountains in 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 mid-stream energy business. From 1997 to 1998 Mr. Zollinger did private consulting work in the mid-stream energy business. From 1993 to 1997, Mr. Zollinger served as Vice President and General Manager for Transportation Services of Total Petroleum, Inc.

John C. Cook was elected Controller in March 2002. He has been Controller for Pacific Energy Group LLC since August 2001 and Controller for Pacific Pipeline System LLC since February 2000. Mr. Cook joined Pacific Pipeline System LLC in February 2000 after having served as Senior Management Consultant from 1998 to 2000, Manager, Vendor Auditing from 1997 to 1998, and Manager, Financial Accounting & Reporting from 1994 to 1997 for ARCO Products Company.

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

We and our General Partner were formed in 2002. Accordingly, our General Partner paid no compensation to its directors and officers with respect to the 2001 fiscal year. We have not accrued obligations with respect to management incentives or benefits for the directors and officers with respect to the 2001 fiscal year. Officers and employees of our General Partner may participate in employee benefit plans and arrangements sponsored by our General Partner, including plans that may be established by the General Partner in the future.

The following table sets forth certain information at December 31, 2002 and for the fiscal year then ended 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**	**Restricted Unit Grants(3)**	**Unit Option Grants**	**All Other Compensation(4)**
Douglas L. Polson(1) Chairman of the Board of Directors	2002	$ 243,883	$ 200,550	$ 2,941,500	50,000	$ 22,823
Irvin Toole, Jr. President, Chief Executive Officer and Director	2002	260,000	190,450	1,470,750		12,305
David E. Wright Executive Vice President, Corporate Development and Marketing	2002	204,875	122,458	735,375		6,306
Lynn T. Wood(2) Vice President, General Counsel and Secretary	2002	156,278	62,798	490,250		13,379
Kevin R. Lee Vice President, Crude Oil Marketing	2002	152,400	65,828	245,125		6,958

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

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

(3) Reflects the value of restricted unit grants as calculated by multiplying the number of units granted by the closing market price on the date of grant.

The number and value of restricted unit holdings at December 31, 2002 for the named officers is as follows:

Name	Number of Restricted Units	Value of Restricted Units
Douglas L. Polson	150,000	$ 2,962,500
Irvin Toole, Jr.	75,000	1,481,250
David E. Wright	37,500	740,625
Lynn T. Wood	25,000	493,750
Kevin R. Lee	12,500	246,875

A restricted unit is a "phantom" unit which entitles the grantee to receive a common unit upon vesting of the phantom unit, or in the discretion of the compensation committee, cash equivalent to the value of a common unit. Please read "Restricted Units" below.

Restricted units which vest in less than 3 years from the date of grant are as follows: 150,000 restricted units granted to Douglas L. Polson vest 50% in July 2003 and 50% in July 2004.

(4)
Reflects employer contribution to 401(K) plan and taxable portion of group term life insurance.

Unit Option Awards

The following table sets forth certain information at December 31, 2002 and for the fiscal year then ended with respect to common unit options granted during 2002 to the individuals named in the Summary Compensation Table above. Mr. Polson was the only person named in the Summary Compensation Table to be granted common unit options. No common unit options were exercised during 2002.

OPTION GRANTS IN THE LAST FISCAL YEAR

Name	Number of Options Granted	Grant Date	Percent of Total Options Granted to Employees in 2002	Exercise Price per Share	Expiration Date	Grant Date Present Value(1)
Douglas L. Polson	50,000	12/23/02	100%	$ 19.50	12/23/12	$ 83,500

(1)
The grant date present value is determined using the Black-Scholes option pricing model and is based on assumptions about future unit price volatility and dividend yield. The following assumptions were used in the Black-Scholes pricing model: estimated volatility 31.9%; risk free rate of return 2.7%; cash dividend yield 9.4% and an exercise date at the end of the contractual term in 2012. The actual value, if any, that may be realized by an executive will depend on the market price of units on the date of exercise. The dollar amounts shown are not intended to forecast possible future appreciation in our unit price.

No options were exercised in 2002.

Equity Compensation Plan Information

The following table sets forth certain information at December 31, 2002 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)

Plan Category	(a) Number Of Securities to be Issued Upon Exercise of Outstanding Options	(b) Weighted Average Exercise Price of Outstanding Options	(c) Number of Securities Remaining Available For Future Issuance Under Equity Compensation Plans (excluding securities reflected in column a)
Equity Compensation Plans Approved By Unitholders			
Equity Compensation Plans Not Approved By Unitholders	50,000	$ 19.50	1,318,750*

* 381,250 restricted units granted in December 2002, a portion of which are shown in the Summary Compensation Table above, have also been deducted from the Plan's 1,750,000 units authorized to arrive at 1,318,750 units available for future issuance. Please read "Restricted Units" below.

Committees, Meetings and Director Compensation

Our General Partner's Board of Directors has the responsibility for establishing broad policies and for our overall direction and management. Our General Partner's Board of Directors held two meetings during 2002. Each director during 2002 attended all of the Board meetings. The Board has established standing committees to consider designated matters. The standing committees of the Board are Audit, Compensation, Conflicts, and Nominating and Governance.

Audit Committee

The members of the Audit Committee are: David L. Lemmon, Chairman; Jim E. Shamas and Robert F. Starzel. 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 two meetings during 2002, and all members of the Committee attended each such meeting.

Compensation Committee

The members of the Compensation Committee are: Jim E. Shamas, Chairman; David L. Lemmon and Robert F. Starzel. The Compensation Committee is responsible for overseeing compensation related decisions for the officers and directors of our General Partner. The Committee held two meetings during 2002, and all members of the Committee attended each such meeting.

Conflicts Committee

The members of the Conflicts Committee are: Jim E. Shamas, Chairman, and David L. Lemmon. The Conflicts Committee is responsible for reviewing specific matters which the Board of Directors believes may involve conflicts of interest between our General Partner or its affiliates and the Partnership. The Conflicts Committee determines whether resolution of the conflict of interest is fair and reasonable to us. The members of the Conflicts Committee are not officers or employees of our

General Partner. The Committee held one meeting during 2002, and both members of the Committee attended the meeting.

Nominating and Governance Committee

The members of the Nominating and Governance Committee are: Robert F. Starzel, Chairman; Douglas L. Polson; David L. Lemmon 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 no meetings in 2002.

Compensation of Directors

No additional remuneration will be paid to officers or employees of our General Partner who also serve as directors. In 2002, our General Partner paid compensation at an annual rate of $30,000 to each director for attending meetings of the Board of Directors as well as committee meetings and serving as committee chairman. In addition, each director will be reimbursed for his out-of-pocket expenses in connection with attending meetings of the Board of Directors or committees. Each director will be fully indemnified by us for his actions associated with being a director to the fullest extent permitted under Delaware law.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), requires directors, officers and persons who beneficially own 10% or more of a class of our equity securities that is registered under Section 12 of the Exchange Act to file with the SEC and the New York Stock Exchange initial reports of ownership and reports of changes in ownership of such securities. These persons are also required to furnish us copies of all 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, and except as discussed below, we believe the directors and officers of our General Partner, and our General Partner in its capacity as a beneficial owner of more than 10% of our equity securities, complied with all filing requirements with respect to our equity securities. Mr. Anschutz, one of our directors, filed a report on Form 5 on March 27, 2003, regarding a gift transaction pursuant to which he received one common unit. This report was not timely filed. Except for the report on Form 5 as to this one unit, Mr. Anschutz complied with all filing requirements with respect to our equity securities.

Employment Agreements

Douglas L. Polson

Mr. Polson entered into an employment agreement with our General Partner effective on October 1, 2002. The employment agreement may be terminated by either Mr. Polson or our General Partner at any time.

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

Under his employment agreement, our General Partner may terminate Mr. Polson's employment for cause or without cause. If Mr. Polson'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. Polson 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. Polson's employment agreement also contains indemnification, non-solicitation and non-disclosure provisions.

Irvin Toole, Jr.

Mr. Toole entered into an employment agreement with our General Partner on January 1, 2002. The employment agreement may be terminated by either Mr. Toole or our General Partner at any time.

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

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

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

David E. Wright

Mr. Wright entered into an employment agreement with our General Partner on January 1, 2002. The employment agreement may be terminated by either Mr. Wright or our General Partner at any time.

The employment agreement provides for an annual base salary and an annual bonus in accordance with our General Partner's annual incentive plan. Mr. Wright is also eligible to participate in all other bonus and benefit programs for which employees and/or senior executives are generally eligible. In addition, he will be reimbursed for reasonable expenses incurred in his capacity as Executive Vice President, Corporate Development and Marketing and will be provided with a vehicle. Upon commencement of his employment, Mr. Wright received a one-time payment. If Mr. Wright resigns or is terminated for cause prior to May 31, 2003, he may be required to repay a portion of this one-time payment.

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 may be terminated by either Mr. Tywoniuk or our General Partner at any time.

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

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

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

Kevin R. Lee

Mr. Lee entered an employment agreement with our General Partner on January 1, 2002. The employment agreement may be terminated by either Mr. Lee or our General Partner at any time.

The employment agreement provides for an annual base salary and an annual bonus in accordance with our General Partner's annual incentive plan. Mr. Lee is guaranteed a minimum annual bonus for the calendar years 2001 and 2002. In addition, he is eligible to earn a special, one-time bonus for the period ending July 1, 2003. The amount of this one-time bonus will be based on the financial performance of Pacific Marketing and Transportation LLC for the period July 1, 2001 through June 30, 2003.

The employment agreement provides that Mr. Lee is eligible to participate in all other bonus and benefit programs for which employees and/or senior executives are generally eligible. In addition, Mr. Lee will be reimbursed for reasonable expenses incurred in his capacity as Vice President, Crude Oil Marketing.

Under his employment agreement, our General Partner may terminate Mr. Lee's employment for cause or without cause. If Mr. Lee'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 one year.

Mr. Lee'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 may be terminated by either Mr. Wood or our General Partner at any time.

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

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

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

Gary L. Zollinger

Mr. Zollinger entered into an employment agreement with our General Partner on January 1, 2002. The employment agreement may be terminated by either Mr. Zollinger or our General Partner at any time.

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

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

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

Long-Term Incentive Plan

General

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

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

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

Restricted Units

A restricted unit is a "phantom" unit. A phantom unit entitles the grantee to receive a common unit upon the vesting of the phantom unit or, in the discretion of the compensation committee, cash equivalent to the value of a common unit. In December 2002 and February 2003, we granted 381,250 and 15,000 restricted units, respectively, to employees of our General Partner. In April 2003, we will grant an additional 9,000 restricted units in aggregate to three outside directors, Messrs. Lemmon, Shamas and Starzel. 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, the grantee's unvested restricted units will be automatically forfeited unless, and to the extent, the compensation committee provides otherwise. In addition, the restricted units will vest upon a change of control of Pacific Energy Partners or our General Partner. The compensation committee, in its discretion, may grant tandem distribution equivalent rights, i.e. the right to receive cash equal to cash distributions made on a common unit, with respect to restricted units; however, none have been granted.

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

Unit Options

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. In December 2002, we granted 50,000 unit options.

Annual Incentive Plan

Our General Partner has adopted Pacific Energy Group LLC's Annual Incentive Compensation Plan. This annual incentive plan is designed to enhance the performance of eligible employees of our General Partner by rewarding them with cash awards for achieving 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 of our General Partner may amend or change the annual incentive plan at any time. We will reimburse our General Partner for payments and costs incurred under the plan.

ITEM 12. Security Ownership of Certain Beneficial Owners and Management

The following table sets forth the beneficial ownership of units of Pacific Energy Partners as of February 28, 2003, held by beneficial owners of more than 5% of the units, by directors of our General Partner, by each named executive officer and by all directors and executive officers of our General Partner as a group.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Subordinated Units Beneficially Owned	Percentage of Subordinated Units Beneficially Owned	Percentage of Total Units Beneficially Owned	Restricted Units Granted(5)
Anschutz Company(1)	1,865,000	17.8%	10,465,000	100%	58.9%	
Pacific Energy GP, Inc.(2)	1,865,000	17.8%	10,465,000	100%	58.9%	
Douglas L. Polson(3)	1,000	*			*	150,000
Philip F. Anschutz(4)	1,865,001	17.8%	10,465,000	100%	58.9%	
Craig D. Slater(3)	10,000	0.1%				
Clifford P. Hickey(3)	2,000	*			*	
David L. Lemmon(3)	100	*			*	
Jim E. Shamas(3)	1,000	*			*	
Robert F. Starzel						
Irvin Toole, Jr.(3)	5,100	*			*	75,000
David E. Wright(3)	1,500	*			*	37,500
Gerald A. Tywoniuk	1,500	*			*	15,000
Arthur G. Diefenbach(3)	300	*			*	12,500
Kevin R. Lee						12,500
Jesse G. Metcalf						12,500
Lynn T. Wood(3)	1,000	*			*	25,000
Gary L. Zollinger						12,500
John D. Cook(3)	500	*			*	6,250
All directors and executive officers as a group (15 persons)	1,889,001	18.0%	10,465,000	100%	59.0%	358,750

(1) The address of Anschutz Company is 555 17th Street, Suite 2400, Denver, Colorado 80202. Anschutz Company is the ultimate parent company of Pacific Energy GP, Inc. and may, therefore, be deemed to beneficially own the units held by Pacific Energy GP, Inc.

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

(3) In each instance a "*" indicates that the individual owns less than 0.1% of the common and total units outstanding.

(4) Mr. Anschutz is the 100% owner of Anschutz Company.

(5) A restricted unit is a "phantom" unit which entitles the grantee to receive a common unit upon vesting of the phantom unit, or in the discretion of the compensation committee, cash equivalent to the value of a common unit. In December 2002 and February 2003, we granted 381,250 and 15,000 restricted units, respectively, to employees of our General Partner. At the date of each grant, the compensation committee determines the period over which restricted units granted to employees and directors will vest and 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, 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. Please read "Item 11 Long-Term Incentive Plan Restricted Units" above.

ITEM 13. Certain Relationships and Related Transactions

Our General Partner owns an aggregate 59.7% interest in us, consisting of a 57.7% limited partner interest, represented by 1,865,000 common units and 10,465,000 subordinated units, and the 2% general partner interest.

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 formation, ongoing operation and any liquidation of Pacific Energy Partners. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm's-length negotiations.

	Formation Stage
The consideration received by our General Partner and its affiliates for the contribution of assets and liabilities to us	1,865,000 common units;
	10,465,000 subordinated units;
	2% general partner interest in Pacific Energy Partners;
	the incentive distribution rights; and
	$105.1 million from the proceeds of the term loan facility.
	Operational Stage
Distributions of available cash to our General Partner	We will generally make cash distributions 98% to the unitholders, including our General Partner, as holder of an aggregate of 1,865,000 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 $800,000 on its 2% general partner interest and approximately $22.8 million on its common units and subordinated units.
Reimbursements to our General Partner and its affiliates	Our General Partner will be entitled to reimbursement for all expenses it incurs on our behalf, including salaries and employee benefit costs for its employees who provide services to us, and all other necessary or appropriate expenses allocable to us or reasonably incurred by our General Partner in connection with operating our business. Our General Partner has sole discretion in determining the amount of these expenses.
Withdrawal or removal of our General Partner	If our General Partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.
Liquidation Stage	
Liquidation	Upon our liquidation, the partners, including our General Partner, will be entitled to receive liquidating distributions according to their particular capital account balances.

Omnibus Agreement

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

- Anschutz's and its affiliates' agreement not to compete with us under certain circumstances; and
- an indemnity by Anschutz for certain environmental liabilities and income tax liabilities.

Noncompetition

Anschutz agreed, and caused its affiliates to agree, for so long as Anschutz controls our General Partner, not to engage in, whether by acquisition or otherwise, the business of transportation of crude oil by pipeline in the United States for any third parties or crude oil storage and terminalling activities in the United States for any third parties. This restriction does not apply to:

- any other businesses of Anschutz or its subsidiaries, including without limitation gathering or marketing activities;
- any activities performed by Anschutz or its subsidiaries primarily in connection with oil and gas properties owned jointly by Anschutz or its subsidiaries with other parties;
- the business activities of certain public and private companies in which Anschutz or its subsidiaries hold an ownership interest;
- any business owned by Anschutz or its subsidiaries on July 26, 2002, the completion date of our initial public offering, including any capital improvements, replacements or direct expansions of these businesses;
- any business that Anschutz or any of its subsidiaries acquires or constructs that has a fair market value of less than $10.0 million for any particular transaction and less than $50.0 million on an aggregate basis within the preceding 12-month period;
- any business that Anschutz or any of its subsidiaries acquires or constructs that has a fair market value of $10.0 million or greater for any particular transaction or $50.0 million or greater on an aggregate basis within the preceding 12-month period, in each case if we have been offered the opportunity to purchase the business for fair market value and we decline to do so with the approval of our conflicts committee; and
- any business that Anschutz or any of its subsidiaries acquires or constructs if we have agreed with Anschutz or any of its subsidiaries in advance, with the approval of our conflicts committee, on the amount and nature of consideration, closing date and other terms upon which we will acquire the business from Anschutz or its subsidiaries after the acquisition or construction of the business by Anschutz or its subsidiaries.

In addition, the limitations on the ability of Anschutz and its affiliates to compete with us may terminate upon a change of control of Anschutz.

Indemnification

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

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

Other Related Party Transactions

ARCO owned a 26.5% ownership interest in PPS from May 1, 1999 through June 7, 2001 and was therefore a related party during this period. During this period, PPS entered into various agreements with ARCO under which ARCO provided operating services to us and leased facility space from us. We also shared certain facilities that supported the operations of both companies. The cost of operating the shared facilities was allocated based on the percentage benefit obtained by both of us. We paid ARCO $0.1 million and $0.2 million in 2000 and 2001, respectively. We received $0.1 million and $0.2 million from ARCO in 2000 and 2001, respectively.

During 2002, PEG received a capital contribution from Anschutz of $8.8 million and paid distributions to Anschutz of $16.0 million prior to the initial public offering in July. Concurrent with the initial public offering, PEG paid a distribution of $105.1 million to Anschutz. Subsequent to the initial public offering the Partnership paid quarterly distributions in respect of the third quarter 2002 to Anschutz of $4.3 million on its common units, subordinated units and 2% General Partner interest.

A subsidiary of Anschutz is a shipper on Line 2000 and is charged published tariff rates. The Partnership charged this subsidiary approximately $3.3 million, $0.2 million, and $2.3 million during 2000, 2001 and 2002, respectively. This subsidiary entered into agreements with a third party to purchase crude oil, ship it on Line 2000, and sell it in the Los Angeles Basin. The amounts associated with these shipments, included in accounts receivable were $0.6 million, $0.1 million and $0.4 million at

December 31, 2000, 2001 and 2002, respectively. As an original sponsor of the Line 2000 project, Anschutz and its subsidiaries qualify for participating shipper tariff rates on the Line 2000 pipeline. Anschutz has designated its rights for participating shipper rates to the Partnership and other affiliates.

An affiliate of Anschutz is a shipper on AREPI pipeline and is charged published tariff rates. The Partnership charged this affiliate transportation fees of $1.2 million, $0.7 million and $0.1 million during 2000, 2001 and 2002, respectively. An affiliate of Anschutz is a shipper on RMP pipeline and is charged published tariff rates. The Partnership charged this affiliate transportation fees of $0.1 million during 2002.

Prior to April 1, 2002, Anschutz employed various personnel who worked directly on AREPI pipeline and provided other executive, accounting and administrative support to AREPI. Most of these employees continue to provide services to AREPI pipeline, but are now employed by the General Partner. For 2000, 2001 and 2002, Anschutz charged AREPI approximately $0.6 million, $0.6 million, and $0.2 million respectively, for salaries of the pipeline related personnel and for various support services. On December 31, 2000 and 2001, AREPI declared and effected dividends to Anschutz of $3.6 million and $2.9 million, respectively. These dividends represented the amount of receivables due from Anschutz and its subsidiaries immediately prior to the dividends.

RMP serves as the contract operator for Anschutz Wahsatch Gathering System, Inc. ("AWGS"), a wholly owned subsidiary of Anschutz that owns a natural gas gathering system in Wyoming and Utah. AWGS reimburses RMP for the direct costs of operating the AWGS assets, such as the salary and benefit costs incurred by the direct assigned field operating and maintenance personnel related to AWGS operations. In addition, AWGS pays an annual management fee of $0.3 million to reimburse RMP for the portion of time spent by management and for other overhead services, related to AWGS activities. As of December 31, 2002, $0.1 million was included in the accounts receivable of RMP on account of these services.

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 our Line 2000 in return for an annual rental. We paid UPC rentals due under this agreement of $3.9 million, $4.0 million and $1.7 million in 2000, 2001 and 2002, respectively. Under the agreement the annual rental is to be adjusted every five years, in accordance with prescribed procedures, to reflect fair rental value. The first revision was to have been made effective as of April 1, 2002, but to date the parties have not completed the revision process. Accordingly, the rental that was paid for 2002 was an estimate, and is subject to subsequent adjustment. Philip F. Anschutz, a director of our General Partner and the sole stockholder of Anschutz Company, the indirect parent of our General Partner, is a director and the Non-Executive Vice Chairman of UPC.

At December 31, 2001, Anschutz was providing letter-of-credit support for PMT activities totaling approximately $21.3 million. PMT reimbursed Anschutz for its cost of providing these letters of credit. Following the formation of the Partnership, such letters of credit were replaced by letters of credit under the Partnership's $200.0 million revolving credit facility.

In 2002, Anschutz paid certain expenses on behalf of RMP. Amounts charged in 2002 for reimbursement were $0.3 million, which is included in "due to related parties" of RMP at December 31, 2002. In 2002, Anschutz paid certain expenses on behalf of RPL. Amounts charged in 2002 for reimbursement were $0.4 million, which is included in "due to related parties" of RPL at December 31, 2002.

We do not have any employees. Our General Partner employs approximately 215 employees who directly support our operations and all expenses incurred by our General Partner are charged to us. At December 31, 2002, amounts due to our General Partner for reimbursement of payroll and related costs amounted to $0.3 million.

In 2002, the Partnership began utilizing the financial accounting system owned and provided by Anschutz under a shared services arrangement. In addition, the Partnership utilizes the services of Anschutz's risk management personnel for acquiring the Partnership's insurance, and the Partnership's surety bonds are issued under Anschutz's bonding line. Out of pocket costs incurred by Anschutz for the benefit of the Partnership for computer consultants, insurance premiums and surety bond costs were reimbursed by the Partnership. Beginning January 2003, the Partnership will pay Anschutz a fee of $0.1 million per year for these services and continue to reimburse Anschutz for any out of pocket costs it incurs. The fixed annual fee includes all license, maintenance and employee costs associated with the Partnership's use of the financial accounting system.

In 2002, Anschutz provided office space to several employees of the Partnership at no cost to the Partnership. Beginning January 2003, the Partnership leased approximately 4,700 square feet of office space from an affiliate of Anschutz, for a term of five years at an initial annual cost of $0.1 million, the prevailing market rate for comparable space. Also beginning in 2003, the Partnership's trucking operation began hauling water for an Anschutz oil and gas subsidiary at rates equivalent to those charged to third parties.

ITEM 14. Controls and Procedures

(a) *Evaluation of disclosure controls and procedures.* Within 90 days before the filing of this report, Irvin Toole, Jr., our Chief Executive Officer, and Gerald A. Tywoniuk, our Chief Financial Officer, evaluated the effectiveness of our disclosure controls and procedures. Based on the evaluation, they believe that:

> Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms; and
>
> Our disclosure controls and procedures were effective to ensure that material information was accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

(b) *Changes in internal controls.* There have been no significant changes in our internal controls or in other factors that could significantly affect our internal controls subsequent to their evaluation, nor have there been any corrective actions with regard to significant deficiencies or material weaknesses.

ITEM 15. Exhibits, Financial Statement Schedules and Reports on Form 8-K.

(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
3.2	First Amended and Restated Agreement of Limited Partnership of Pacific Energy Partners, L.P. (incorporated by reference to Exhibit 3.2 to Pacific Energy Partners, L.P.'s quarterly report on Form 10-Q for the quarter ended June 30, 2002)
3.7	Second Amended and Restated Operating Agreement of Pacific Energy Group LLC (incorporated by reference to Exhibit 3.7 to Pacific Energy Partners, L.P.'s quarterly report on Form 10-Q for the quarter ended June 30, 2002)
10.1	Credit Agreement (incorporated by reference to Exhibit 10.1 to Pacific Energy Partners, L.P.'s quarterly report on Form 10-Q for the quarter ended June 30, 2002)
10.3	Contribution and Conveyance Agreement (incorporated by reference to Exhibit 10.3 to Pacific Energy Partners, L.P.'s quarterly report on Form 10-Q for the quarter ended June 30, 2002

Exhibit Number	Description
10.4	Employment Agreement between Pacific Energy GP, Inc. and Irvin Toole, Jr. (incorporated by reference to Exhibit 10.4 to Pacific Energy Partners, L.P.'s Amendment No. 3 to Form S-1)
10.5	Employment Agreement between Pacific Energy GP, Inc. and David E. Wright (incorporated by reference to Exhibit 10.5 to Pacific Energy Partners, L.P.'s Amendment No. 3 to Form S-1)
10.6	Employment Agreement between Pacific Energy GP, Inc. and Gary L. Zollinger (incorporated by reference to Exhibit 10.6 to Pacific Energy Partners, L.P.'s Amendment No. 3 to Form S-1)
10.7	Employment Agreement between Pacific Energy GP, Inc. and Kevin K. Lee (incorporated by reference to Exhibit 10.7 to Pacific Energy Partners, L.P.'s Amendment No. 3 to Form S-1)
10.10	Omnibus Agreement (incorporated by reference to Exhibit 10.10 to Pacific Energy Partners, L.P.'s quarterly report on Form 10-Q for the quarter ended June 30, 2002)
10.11	Form of Pacific Energy GP, Inc. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.8(b) to Pacific Energy Partners, L.P.'s Amendment No. 4 to Form S-1)
10.12	Employment Agreement between Pacific Energy GP, Inc. and Douglas L. Polson
10.13	Employment Agreement between Pacific Energy GP, Inc. and Gerald A. Tywoniuk
10.14	Employment Agreement between Pacific Energy GP, Inc. and Lynn T. Wood
10.15	Form of Pacific Energy GP, Inc. Annual Incentive Plan (incorporated by reference to Exhibit 10.8(b) to Pacific Energy Partners, L.P.'s Amendment No. 4 to Form S-1)
21.1	List of Subsidiaries of Pacific Energy Partners, L.P.

(B) Reports on Form 8-K:

Form 8-K as filed on February 3, 2003 to comply with Regulation FD (Fair Disclosure) disclosure requirements concerning the Partnership's earnings release in January 2003.

SIGNATURES

Pursuant to the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, 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, INC.
its General Partner

March 25, 2003 By: /s/ IRVIN TOOLE, JR.

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

March 25, 2003 By: /s/ GERALD A. TYWONIUK

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

Pursuant to the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons in the capacities and on the dates indicated.

Date	Signature	Title
March 25, 2003	/s/ DOUGLAS L. POLSON Douglas L. Polson	Chairman of the Board of Directors
March 25, 2003	/s/ PHILIP F. ANSCHUTZ Philip F. Anschutz	Director
March 25, 2003	/s/ CLIFFORD P. HICKEY Clifford P. Hickey	Director
March 25, 2003	/s/ CRAIG D. SLATER Craig D. Slater	Director
March 25, 2003	/s/ DAVID L. LEMMON David L. Lemmon	Director
March 25, 2003	/s/ JIM E. SHAMAS Jim E. Shamas	Director
March 25, 2003	/s/ ROBERT F. STARZEL Robert F. Starzel	Director

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Irvin Toole, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of Pacific Energy Partners, L.P.;

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

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act rules 13a-14 and 15d-14) for the registrant and have:

   a)

designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's Board of Directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

March 25, 2003

/s/ IRVIN TOOLE, JR.

Irvin Toole, Jr.
President and Chief Executive Officer
Pacific Energy GP, Inc.,
General Partner of
Pacific Energy Partners, L.P.

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Gerald A. Tywoniuk, certify that:

1. I have reviewed this annual report on Form 10-K of Pacific Energy Partners, L.P.;

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

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act rules 13a-14 and 15d-14) for the registrant and have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's Board of Directors (or persons performing the equivalent function):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

March 25, 2003

/s/ GERALD A. TYWONIUK

Gerald A. Tywoniuk
Senior Vice President, Chief Financial Officer and Treasurer
Pacific Energy GP, Inc.,
General Partner of
Pacific Energy Partners, L.P.

INDEX TO FINANCIAL STATEMENTS

Independent Auditors' Report

The Board of Directors
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, 2002 and 2001 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, 2002. 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 auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated 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. as of December 31, 2002 and 2001 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America.

/s/ KPMG LLP

KPMG LLP

Los Angeles, California
January 28, 2003

PACIFIC ENERGY PARTNERS, L.P. (Note 1)

Successor to Pacific Energy (Predecessor)

CONSOLIDATED BALANCE SHEETS

December 31, 2001 and 2002

	2001	2002
	(in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 9,511	$ 23,873
Crude oil sales receivable	21,538	24,157

	2001	2002
Transportation accounts receivable	5,770	10,568
Due from related party (note 8)	108	
Crude oil inventory	2,292	3,887
Spare parts inventory	445	445
Prepaid expenses	1,684	2,720
Other	470	421
Total current assets	41,818	66,071
Property and equipment, net	309,675	404,842
Investment in Frontier	9,444	9,175
Due from related parties (note 8)	11	
Other assets	11,231	6,950
	$ 372,179	$ 487,038
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 788	$ 2,752
Accrued crude oil purchases	22,049	24,385
Provision for right-of-way costs (note 9)	982	350
Accrued power costs	1,634	1,706
Accrued interest payable	841	2,542
Due to related parties		952
Provision for loss on rate case litigation (note 14)	1,500	
Derivatives liability current portion (note 1)		4,775
Other	2,969	4,181
Total current liabilities	30,763	41,643
Long-term debt (note 7)	181,333	225,000
Due to related parties (note 8)	122	
Derivatives liability (note 1)		2,600
Other liabilities (note 14)	2,600	2,600
Total liabilities	214,818	271,843
Commitments and contingencies (notes 2 and 14)		
Partners' Capital:		
Common unitholders (10,465,000 units outstanding at December 31, 2002)		163,172
Subordinated unitholders (10,465,000 units outstanding at December 31, 2002)		57,069
General Partner interest		2,329
Accumulated other comprehensive loss (note 1)		(7,375)
Net parent investment	157,361	
Net partners' capital (net parent investment)	157,361	215,195
	$ 372,179	$ 487,038

See accompanying notes to consolidated financial statements.

PACIFIC ENERGY PARTNERS, L. P. (Note 1)

Successor to Pacific Energy (Predecessor)

CONSOLIDATED STATEMENTS OF INCOME

Years ended December 31, 2000, 2001 and 2002

	2000	2001	2002
		(in thousands)	
Pipeline transportation revenue	$ 71,419	$ 66,236	$ 102,353
Crude oil sales, net of purchases of $158,293 and $314,903 for the years ended December 31, 2001 and 2002, respectively		9,028	22,158
Net revenue before operating expenses	71,419	75,264	124,511
Expenses:			
Operating	26,988	34,382	54,343
Transition costs (note 3)		220	2,634
General and administrative	2,672	4,134	8,622
Rate case litigation settlement		1,853	
Depreciation and amortization	11,873	11,368	15,919
	41,533	51,957	81,518
Share of net income of Frontier	1,738	1,569	1,347
Operating income	31,624	24,876	44,340
Other income	357	467	516
Interest income	474	320	385
Interest expense	(18,115)	(10,056)	(11,667)
Net income	$ 14,340	$ 15,607	$ 33,574
Net income for the period from January 1 through July 25, 2002			$ 21,757
Net income for the general partner interest for the period from July 26 through December 31, 2002			236
Net income for the limited partner interest for the period from July 26 through December 31, 2002			11,581
Net income			$ 33,574
Net income for the limited partner interest for the period from July 26 through December 31, 2002			$ 11,581
Weighted average limited partner units outstanding for the period from July 26 through December 31, 2002			20,930
Net income per limited partner unit			$ 0.55

See accompanying notes to consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. (Note 1)

Successor to Pacific Energy (Predecessor)

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL

Years ended December 31, 2000, 2001 and 2002

		Limited Partner Units		Limited Partner Amounts				
	Net Parent Investment	Common	Subordinated	Common	Subordinated	General Partner Interest	Accumulated Other Comprehensive Loss	Total
	(in thousands)							
Balance, December 31, 1999	$ 121,873			$	$	$	$	$ 121,873
Capital contributions of members	915							915
Distributions to members	(19,600)							(19,600)
Net income for the period of January 1 - December 31, 2000	14,340							14,340
Balance, December 31, 2000	$ 117,528			$	$	$	$	$ 117,528
Capital contributions of members	90,649							90,649
Purchase of BP interest in joint venture	(43,607)							(43,607)
Distributions to members	(22,816)							(22,816)
Net income for the period of January 1 - December 31, 2001	15,607							15,607
Balance, December 31, 2001	$ 157,361			$	$	$	$	$ 157,361
Capital contributions of members	8,770							8,770
Distributions to members	(16,000)							(16,000)
Net income for the period of January 1 - July 25, 2002	21,757							21,757
Balance, July 26, 2002	$ 171,888			$	$	$	$	$ 171,888
Distribution to general partner in connection with the initial public offering	(105,081)							(105,081)
Contribution to limited partnership	(66,807)	1,865	10,465	9,767	54,803	2,237		
Proceeds from offering of limited partner interests, net		8,600		151,139				151,139
Distribution to limited partners (post initial public offering)				(3,524)	(3,525)			(7,049)
Distribution to general partner (post initial public offering)						(144)		(144)
Net income for the period July 26-December 31,				5,790	5,791	236		11,817

		Limited Partner Units		Limited Partner Amounts			Accumulated Other Comprehensive Loss	
2002								
Change in fair value of interest rate hedging derivatives (note 1)							(7,375)	(7,375)
Balance, December 31, 2002	$	10,465	10,465	$ 163,172	$ 57,069	$ 2,329	$ (7,375)	$ 215,195

See accompanying notes to consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. (Note 1)

Successor to Pacific Energy (Predecessor)

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years ended December 31, 2000, 2001 and 2002

	2000	2001	2002
		(in thousands)	
Net income	$ 14,340	$ 15,607	$ 33,574
Change in fair value of interest rate hedging derivatives			(7,375)
Comprehensive income	$ 14,340	$ 15,607	$ 26,199

See accompanying notes to consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. (Note 1)

Successor to Pacific Energy (Predecessor)

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2000	2001	2002
		(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 14,340	$ 15,607	$ 33,574
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	11,873	11,368	15,919
Amortization of debt issue costs			471
Share of net income of Frontier	(1,738)	(1,569)	(1,347)
	24,475	25,406	48,617
Net changes in operating assets and liabilities:			

	Year Ended December 31,		
Crude oil sales receivable		(21,538)	(2,619)
Transportation accounts receivable	(1,101)	1,296	(4,798)
Due to related party	(1,084)	406	1,071
Crude oil inventory	(830)	(376)	(1,595)
Spare parts inventory	47	14	
Prepaid expenses	47	(416)	(1,036)
Other current and non-current assets	29	(807)	(245)
Accounts payable	(180)	(801)	1,964
Accrued crude oil purchases		22,049	2,336
Accrued right-of-way costs		982	(632)
Accrued power costs	(936)	1,247	72
Accrued interest payable	4,254	(3,537)	1,701
Distributions from Frontier, net	1,581	2,098	1,245
Provision for loss on rate case litigation		1,500	(1,500)
Other current and non-current liabilities	17	(1,117)	1,212
	1,844	1,000	(2,824)
NET CASH PROVIDED BY OPERATING ACTIVITIES	26,319	26,406	45,793
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to property and equipment	(3,487)	(5,814)	(6,000)
Acquisition of gathering, storage and blending assets		(12,144)	
Deposit made on pipeline acquisition		(10,662)	
Acquisition of additional interest in Frontier		(8,583)	
Acquisition of pipeline assets			(95,311)
NET CASH USED IN INVESTING ACTIVITIES	(3,487)	(37,203)	(101,311)
CASH FLOWS FROM FINANCING ACTIVITIES			
Related party note payable		4,933	
Capital contributions of members (pre initial offering)	915	90,649	8,770
Distributions to members (pre initial public offering)	(19,600)	(22,817)	(16,000)
Distributions to general partner in connection with the initial public offering			(105,081)
Proceeds from note payable to bank			312,000
Payment of debt issue costs			(5,300)
Repayment of long-term debt		(63,600)	(268,333)
Proceeds from issuance of common units			167,700
Common units issuance and registration costs			(16,407)
Distributions to limited partners (post initial public offering)			(7,049)
Distributions to general partner (post initial public offering)			(144)
Due from related party	1,114	(1,121)	(276)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	(17,571)	8,044	69,880
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	5,261	(2,753)	14,362
CASH AND CASH EQUIVALENTS, beginning of reporting period	7,003	12,264	9,511
CASH AND CASH EQUIVALENTS, end of reporting period	$ 12,264	$ 9,511	$ 23,873
Supplemental disclosure cash paid for interest	$ 13,681	$ 13,487	$ 8,551

	Year Ended December 31,		

See accompanying notes to consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P.

Successor to Pacific Energy (Predecessor)

Notes to Consolidated Financial Statements

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

On July 26, 2002, Pacific Energy Partners, L.P. (the "Partnership") completed an initial public offering of common units representing limited partner interests in the Partnership. The Partnership, which was formed by The Anschutz Corporation ("Anschutz") in February 2002, and its subsidiaries are engaged in gathering, blending, transporting, storing and distributing crude oil.

Anschutz, through Pacific Energy GP, Inc., an indirect, wholly-owned subsidiary of Anschutz and the general partner of the Partnership (the "General Partner"), conveyed to the Partnership its ownership interests in Pacific Energy Group LLC ("PEG"), whose subsidiaries consist of: (i) Pacific Pipeline System LLC ("PPS"), owner of Line 2000 and the Line 63 system, (ii) Pacific Marketing and Transportation LLC ("PMT"), (iii) Rocky Mountain Pipeline System LLC ("RMP"), owner of the Western Corridor system and the Salt Lake City Core system assets purchased from an affiliate of BP plc on March 1, 2002, (iv) Anschutz Ranch East Pipeline LLC ("AREPI"), owner of AREPI pipeline and successor to Anschutz Ranch East Pipeline, Inc., and (v) Ranch Pipeline LLC ("RPL"), the owner of a 22.22% partnership interest in Frontier Pipeline Company ("Frontier") and successor to Ranch Pipeline, Inc. Anschutz made this conveyance in exchange for: (i) the continuation of its 2% General Partner interest in the Partnership; (ii) incentive distribution rights (as defined in its partnership agreement); (iii) 1,865,000 common units; (iv) 10,465,000 subordinated units; and (v) $105.1 million from borrowings under PEG's term loan on closing of the initial public offering.

PPS, PMT, AREPI, RMP and RPL, each subsidiaries of PEG, collectively, constitute the Partnership's predecessor, which is referred to herein as "Pacific Energy (Predecessor)" or the "Predecessor." The financial data and results of operations of PPS, PMT, AREPI, RMP and RPL, are presented on a consolidated basis as the financial data and results of operations of the Partnership, the successor to Pacific Energy (Predecessor). The transfer of ownership interests in the entities that constitute Pacific Energy (Predecessor) to the Partnership represented a reorganization of entities under common control and was recorded at historical cost. The consolidated financial statements (combined prior to July 26, 2002) includes the financial position, results of operations, changes in partners' capital and cash flows of the Partnership, PEG, PPS, PMT, RMP, AREPI and RPL. All significant intercompany balances and transactions have been eliminated during the consolidation process.

Description of Business and History

PEG was formed in August 2001, and at December 31, 2002 owned 100% of PPS, PMT, RMP, AREPI and RPL.

PPS owns and operates two crude oil pipelines, Line 2000 and the Line 63 System. In early 1999, PPS completed construction of Line 2000, a 130-mile crude oil pipeline that extends from Kern County in the San Joaquin Valley of California to the Los Angeles Basin where it has direct and indirect connections to various refineries and terminal facilities. Line 2000 has a permitted annual average throughput capacity of 130,000 barrels of crude oil per day. Shipments of crude oil on Line 2000 began on February 23, 1999.

Effective May 1, 1999, ARCO Midcon, formerly ARCO Pipe Line Company ("ARCO"), exchanged its Line 63 assets for a 26.5% ownership interest in PPS and a note of $63.6 million. On June 7, 2001,

ARCO made a capital contribution of $63.6 million to PPS. PPS Holding Company ("Holdings"), a wholly owned subsidiary of Anschutz and the 100% owner of the General Partner, then purchased ARCO's ownership interest in PPS for $47.0 million in cash, and PPS repaid the $63.6 million note. This purchase of an additional ownership interest resulted in negative goodwill of $40.6 million, which was allocated proportionately to reduce property, plant and equipment of PPS.

The Line 63 System includes a 107-mile crude oil pipeline capable of shipping approximately 105,000 barrels of crude oil per day from the San Joaquin Valley to various refineries and delivery points in the Los Angeles Basin and in Bakersfield. The Line 63 System also includes storage assets, various gathering and distribution lines in the San Joaquin Valley, crude oil distribution lines in the Los Angeles Basin and a delivery facility in the Los Angeles Basin.

PMT was formed in June 2001, in connection with the purchase of certain assets in the San Joaquin Valley for approximately $14.4 million. The assets acquired consist of 122 miles of intrastate crude oil gathering pipelines and six storage and blending facilities with approximately 254,000 barrels of storage capacity and blending capacity of up to 65,000 barrels per day as well as a base stock of crude oil. The purchase price was allocated among the fair values of the assets acquired and no goodwill resulted from this acquisition. The purchase price is subject to adjustment based on operating cash flows as defined in the purchase agreement for the 24 months following the acquisition. Depending on the amount of this cash flow, the purchase price could decrease by up to $1.5 million or increase by up to $7.5 million. Based on such cash flows through December 31, 2002, it cannot be determined whether any additional consideration will be paid.

RMP was formed in December 2001 in connection with the acquisition on March 1, 2002 of certain pipeline and related assets located in the Rocky Mountain region from an affiliate of BP plc for approximately $107.0 million. The pipeline and related assets acquired by RMP consist of various ownership interests in 1,925 miles of intrastate and interstate crude oil transportation pipelines, 209 miles of gathering pipelines and 29 storage tanks with approximately 1.4 million barrels of storage capacity. The purchase price was allocated among the fair values of the assets acquired, and no goodwill resulted from this acquisition.

AREPI, which was transferred to PEG on July 12, 2002 in preparation for the Partnership's initial public offering, owns and operates a 42-mile crude oil pipeline with a throughput capacity of 52,500 barrels per day. The AREPI pipeline originates 21 miles south of Evanston, Wyoming at Ranch Station, Utah where it connects with the Frontier pipeline (discussed below) and terminates at Kimball Junction, Utah, where it connects with a ChevronTexaco pipeline that serves the Salt Lake City refineries.

RPL, which was transferred to PEG on March 1, 2002 in preparation for the Partnership's initial public offering, owns a 22.2% partnership interest in Frontier, a Wyoming general partnership, which owns Frontier pipeline. RPL owned a 12.5% partnership interest in Frontier until December 2001, at which time it acquired an additional 9.72% partnership interest from an affiliate of BP plc for $8.6 million. Frontier pipeline is a 290-mile pipeline with a throughput capacity of 62,200 barrels per day that originates in Casper, Wyoming and delivers crude oil to the AREPI pipeline and the Salt Lake City Core System.

Statement of Income Presentation

In conjunction with the Partnership's pipeline transportation operations, the Partnership routinely purchases, gathers and blends crude oil, which is then transported on its pipelines and sold to third parties. The sales resulting from these activities are presented in the consolidated statement of income net of the cost to purchase the crude oil as the activities are ancillary in nature to the Partnership's pipeline transportation operations.

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 components of property and equipment, the expected costs of environmental remediation, and contingent liabilities.

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.

Crude Oil Inventory

Pursuant to its tariff filings, the Partnership is entitled to a percentage (pipeline loss allowance) of barrels transported through the regulated pipelines. As these barrels are earned each month, the Partnership recognizes revenue and a corresponding increase in crude oil inventory based on average crude prices for that month. The crude oil inventory balance is subject to downward adjustment each quarter if crude prices decline below the carrying value of the inventory. The Partnership generally sells these barrels when it accumulates a salable quantity. As the sales occur, a gain or loss is recognized based on the difference between the sales price and the inventory carrying value, as adjusted, and is recorded to pipeline transportation revenue.

Spare Parts Inventory

Spare parts inventory is stated at cost using the first-in, first-out method.

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
Buildings and oil tanks	30 years
Station and pumping equipment	15 - 20 years
Other	3 - 10 years

Environmental Remediation

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

Investments

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

Impairment of Long-Lived Assets

Long-lived assets are reviewed for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. This review consists of a comparison of the carrying value of the asset with the asset's expected future undiscounted cash flows without interest costs. Estimates of expected future cash flows are to 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, an 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 adopted Statement of Financial Accounting Standards No. 144 ("SFAS No. 144"), "Accounting for the Impairment or Disposal of Long-Lived Assets," effective January 1, 2002, which did not have any impact on the Partnership's financial position or results from operations.

Revenue Recognition

The Public Utilities Commission of the State of California ("CPUC") economically 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, and revenue is recognized when the transported crude

oil volumes are delivered to a tariff destination point. Tariffs on Line 2000 are market-based, established based on market considerations subject to certain contractual restraints. Tariffs on Line 63 are cost-of-service based, developed based on the 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.

AREPI and Frontier are common carriers under the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). AREPI and Frontier transport crude oil under various cost-based tariff agreements at published rates, depending on the type and quality of the crude oil. RMP is a common carrier under the jurisdiction of both the FERC and the Wyoming Public Service Commission.

Pipeline transportation revenue is typically recognized upon delivery of the crude oil to the customer.

Crude oil sales are recognized as the crude oil is delivered to customers.

Transition Costs

Transition costs include one-time costs incurred in connection with the transition of the operations of acquired assets from the seller to the Partnership and one-time payments made to BP and EOTT to provide certain interim operations support and financial system services related to the acquisition of BP's Western Corridor system and the Salt Lake City Core system assets and EOTT's gathering and blending assets.

Derivative Instruments

The Partnership uses, on a limited basis, certain derivative instruments (principally futures and options) to hedge its minimal exposure to market price volatility related to its sales of crude oil. The Partnership does not engage in speculative derivative activities of any kind. Derivative instruments are included in other assets in the accompanying consolidated balance sheets. Changes in the fair value of the Partnership's derivatives related to crude oil sales are recognized in net income. In 2002, operating expenses include $0.4 million related to changes in fair value of the PMT's derivative instruments for its marketing activities and pipeline transportation revenue is net of $0.2 million related to changes in the fair value of PPS's derivative instruments for its pipeline loss allowance inventory.

In August and September 2002, PEG entered into three interest rate swap agreements pursuant to which it executed five interest rate swap transactions that mature in 2009, totaling $140.0 million, and two interest rate swap transactions that mature in 2007, totaling $30.0 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 the term loan facility. The average swap rate on this $170.0 million of debt is approximately 4.25%, resulting in an all-in interest rate on the $170.0 million of approximately 7.00% (including the current applicable margin of 2.75%).

As of December 31, 2002, interest rates, as measured by market quotations for the future periods covered by the interest rate swap agreements, had declined as compared to August and September 2002, when PEG entered into these interest rate swap agreements. This decline resulted in an unrealized loss of $7.4 million on the aggregate interest rate hedge, which is recorded as a liability

at December 31, 2002. The $7.4 million liability is shown on the consolidated balance sheet in two components, a current liability of $4.8 million, and a long term liability of $2.6 million. The unrealized loss is shown in "other comprehensive income," a component of partners' capital, and not in the consolidated income statement. Should interest rates remain unchanged from the December 31, 2002 market quotations for these future periods, actual losses realized on the interest rate swap agreements in each of the future periods would be offset by the benefit of lower floating rates in those periods, such that total net interest expense on the $170.0 million of hedged debt would be fixed at the all-in interest rate of 7.00%.

By using derivative financial instruments to hedge exposures related to changes in market prices, and interest rates, the Partnership exposes itself to market risk and credit risk. Market risk is the adverse effect on the value of a financial instrument that results from a change in interest rates, currency exchange rates or market prices. 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 failure of the counterparty to perform under the terms of the derivative agreement. When the fair value of a derivative agreement is positive, the counterparty owes the Partnership, which creates credit risk for the Partnership. When the fair value of a derivative agreement is negative, the Partnership owes the counterparty and, therefore, it does not possess credit risk. As of December 31, 2002, the counterparties to the interest rate swap agreements did not possess a credit risk to the Partnership as the fair value of each derivative agreement was negative.

Concentration of Customers and Credit Risk

A substantial portion of the PPS's transportation business in 2000, 2001 and 2002 was with five customers who accounted for approximately 90%, 91% and 93% of West Coast transportation revenue. Two of these customers, ChevronTexaco and Shell Trading Company (who accounted for approximately 53%, 65% and 68% of 2000, 2001 and 2002 gross revenue) have executed ten-year ship or pay agreements, expiring in 2009, with the Partnership whereby they have committed to ship minimum volumes that represent approximately 69% of their actual 2002 transported volumes. These agreements mitigate the potential adverse consequences of the concentration of customers of the Partnership.

PMT also has a sales concentration with three customers who accounted for 72% of PMT's crude oil sales in 2001 and 2002.

A substantial portion of the Partnership's Rocky Mountain transportation business in 2000, 2001 and 2002 was with five customers who, in total, accounted for approximately 89%, 85% and 75% of total Rocky Mountain transportation revenue in those years.

Although the above concentration could affect the Partnership's overall exposure to credit risk, management believes that the Partnership is exposed to minimal risk since a majority of its business is conducted with major, high credit quality companies within the industry. The Partnership performs periodic credit evaluations of its customers' financial condition and generally does not require collateral for its accounts receivables. In some cases, the Partnership requires payment in advance or security in the form of a letter of credit or bank guarantee.

Income Taxes

No provision for federal or state income taxes related to operations is included in the accompanying consolidated financial statements.

The Partnership is not a taxable entity and is not subject to federal or state income taxes as the tax effect of operations is accrued to the unitholders. 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 First Amended and Restated Agreement of Limited Partnership. Individual unitholders have different investment bases depending upon the timing and price of acquisition of partnership units. Further, each unitholder's tax accounting, which is partially dependent upon the unitholder's tax position differs from the accounting followed in the consolidated financial statements. Accordingly, the aggregate difference in the basis of the Partnership's net assets for financial and tax reporting purposes cannot be readily determined because information regarding each unitholder's tax attributes in the Partnership is not available to the Partnership.

In addition to federal and state income taxes, unitholders may be subject to other taxes, such as local, estate, inheritance or intangible taxes which may be imposed by the various jurisdictions in which the Partnership does business or owns property.

Business Segment Reporting

The business segments of the Partnership consist of two geographic regions, the West Coast and the Rocky Mountains. Information relating to these segments is summarized in note 12.

Net Income per Unit

Net income per unit is determined by dividing net income, after deducting the amount allocated to the General Partner interest, by the weighted average number of outstanding common units.

Restricted Units and Unit Options

As permitted under Statement of Financial Accounting Standards No. 123 ("SFAS No. 123"), "Accounting for Stock-Based Compensation," the Partnership has elected to measure costs for restricted units and unit options using the intrinsic value method, as prescribed by Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees." Compensation expense related to the restricted units has been recognized in the accompanying financial statements over the vesting periods of the units and no compensation expense related to the unit options has been recognized in the accompanying financial statements. See note 10 for a discussion of the pro forma effects on results of operations of using the intrinsic value method instead of the fair value method under SFAS No. 123.

Reclassifications

Certain reclassifications have been made to prior years' consolidated financial statements to conform to the current year presentation.

Financial Instruments

The carrying amounts of cash and cash equivalents, accounts receivable, accounts payable and other liabilities approximate their fair value. The carrying value of the Partnership's long-term debt together with the derivatives liability approximates the fair value of the debt as the interest rates reset periodically.

Recent Accounting Pronouncements

In December 2002, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 148 ("SFAS No. 148"), "Accounting for Stock-Based Compensation Transition and Disclosure." SFAS No. 148 amends SFAS No. 123 to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. Furthermore, SFAS No. 148 amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. SFAS No. 148 is effective for fiscal years ending after December 15, 2002. The Partnership has included the required disclosure in note 10 below.

In January 2003, the FASB issued FASB Interpretation No. 46 ("FIN 46"), "Consolidation of Variable Interest Entities." This interpretation clarifies the application of Accounting Research Bulletin No. 51 ("ARB 51"), "Consolidated Financial Statements," and requires companies to evaluate variable interest entities for specific characteristics to determine whether additional consolidation and disclosure requirements apply. This interpretation is immediately applicable for variable interest entities created after January 31, 2003, and applies to fiscal periods beginning after June 15, 2003 for variable interest entities acquired prior to February 1, 2003. The Partnership does not expect that the adoption of this interpretation will have any impact on its financial position or results of operations.

In November 2002, the FASB issued FASB Interpretation No. 45 ("FIN 45"), "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." This interpretation clarifies the requirements of a guarantor in accounting for and disclosing certain guarantees issued and outstanding. This interpretation is effective for fiscal years ending after December 15, 2002. The adoption of this interpretation did not have any impact on the Partnership's financial position or results of operations in 2002.

In July 2002, the FASB issued Statement of Financial Accounting Standards No. 146 ("SFAS No. 146"), "Accounting for Costs Associated with Exit or Disposal Activities." SFAS No. 146 nullifies Emerging Issues Task Force ("EITF") Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." It requires that a liability be recognized for those costs only when the liability is incurred, that is, when it meets the definition of a liability in the FASB's conceptual framework. SFAS No. 146 also establishes fair value as the objective for initial measurement of liabilities related to exit or disposal activities. SFAS No. 146 is effective for exit or disposal activities that are initiated after December 31, 2002, with earlier adoption encouraged. The Partnership does not expect that the adoption of this standard will have any impact on its financial position or results of operations.

In April 2002, the FASB issued Statement of Financial Accounting Standards No. 145 ("SFAS No. 145"), "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections." The rescission of FASB Statement No. 4 ("Statement 4"), "Reporting Gains and Losses from Extinguishment of Debt," and FASB Statement No 64, "Extinguishments of Debt Made to Satisfy Sinking-Fund Requirements," which amended Statement 4, will affect income statement classification of gains and losses from extinguishment of debt. Upon adoption, enterprises must reclassify prior period items that do not meet the extraordinary item classification criteria in Accounting Principles Bulletin No. 30, "Reporting the Results of Operations." The provisions of SFAS No. 145 related to the rescission of Statement 4 are applicable in fiscal years beginning after May 15, 2002, with early application encouraged. The provisions of SFAS No. 145 related to FASB Statement No. 13, "Accounting for Leases," are effective for transactions occurring after May 15, 2002, with early application encouraged. All other provisions of SFAS No. 145 are effective for financial statements issued on or after May 15, 2002, with early application encouraged. The Partnership does not expect that the adoption of SFAS No. 145 will have any impact on its financial position or results from operations.

In August 2001, the FASB issued Statement of Financial Accounting Standards No. 143 ("SFAS No. 143"), "Accounting for Asset Retirement Obligations." This statement requires entities to record the fair value of a liability for legal obligations associated with the retirement obligations of tangible long-lived assets in the period in which it is incurred. When the liability is initially recorded, the entity increases the carrying amount of the related long-lived asset. Over time, accretion of the liability is recognized each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. The standard is effective for fiscal years beginning after June 15, 2002, with earlier adoption encouraged.

Effective January 1, 2003, the Partnership adopted SFAS No. 143, as required. Determination of the amounts to be recognized is based upon numerous estimates and assumptions, including future retirement costs, future inflation rates and the credit-adjusted risk-free interest rate. A substantial portion of our assets have obligations to perform removal and/or remediation activities when the asset is retired. However, the fair value of the asset retirement obligation cannot be reasonably estimated, as the retirement dates are indeterminate. The Partnership will record such asset retirement obligation in the period in which the retirement dates are determined. The cumulative effect of adopting this standard did not have a material impact on the Partnership's financial position, results of operations or cash flows.

2. PENDING ACQUISITION

In February 2002, Holdings, entered into an asset purchase agreement to acquire certain crude oil terminal and pipeline assets of Edison Pipeline and Terminal Company ("EPTC"), a division of Southern California Edison Company (the "ETPC Assets") for approximately $158.2 million, plus potential increases for certain pre-closing adjustments estimated to be between $5 million and $10 million. This acquisition is subject to approval of the CPUC and the satisfaction of other conditions and is not expected to close until the second quarter of 2003. Under an agreement with the

Partnership, Holdings has agreed to transfer all of its interest in Pacific Terminals LLC to the Partnership on or prior to the date the EPTC acquisition is closed.

3. PROPERTY AND EQUIPMENT

Property and equipment consists of the following amounts at December 31, 2001 and 2002:

	2001	2002
	(in thousands)	
Pipeline	$ 268,829	$ 360,032
Station and pumping equipment	37, 018	50,691
Buildings	10,777	12,044
Land and other	29,067	33,349
	345,691	456,116
Less accumulated depreciation	36,016	51,274
	$ 309,675	$ 404,842

The 2001 purchase of ARCO's ownership interest in PPS described in note 1 resulted in negative goodwill of $40.6 million, which was allocated proportionately to reduce pipeline assets of PPS.

4. INVESTMENT IN FRONTIER PIPELINE COMPANY

Prior to December 17, 2001, RPL owned a 12.5% partnership interest in Frontier. On December 17, 2001, RPL purchased an additional 9.72% interest in Frontier for $8.6 million, which increased its ownership in Frontier to 22.2%. RMP became the operator of Frontier concurrent with this acquisition. RPL's investment in Frontier exceeded its proportionate share of Frontier's partners' capital at December 31, 2001 by approximately $7.1 million. This excess was associated with the value of Frontier's pipeline assets and is being amortized over twenty years, the remaining estimated useful life of the pipeline.

The condensed balance sheets of Frontier at December 31, 2001 and 2002 and the statements of income for the years ended December 31, 2000, 2001 and 2002 are presented below (unaudited):

Balance Sheets

	2001	2002
	(in thousands)	
Current assets	$ 5,039	$ 4,481
Property and equipment, net	9,559	9,252
Other assets	1	1
	$ 14,599	$ 13,734

	2001	2002
Current liabilities	$ 1,568	$ 365
Other liabilities	2,425	2,298
Partners' capital	10,606	11,071
	$ 14,599	$ 13,734

Statements of Income

	2000	2001	2002
		(in thousands)	
Revenue	$ 14,651	$ 14,796	$ 11,253
Operating expense	(1,451)	(2,667)	(2,520)
Depreciation expense	(308)	(329)	(359)
Operating income	12,892	11,800	8,374
Rate case litigation settlement			(2,504)
Other income	1,011	583	194
Net income	$ 13,903	$ 12,383	$ 6,064

5. LEASES

The Partnership is obligated under several noncancelable operating leases, primarily for the rental of office space and trucks which expire through the year 2007. These leases require the Partnership to pay all operating costs such as maintenance and insurance. Rental expense for all operating leases during the years ended December 31, 2000, 2001 and 2002 amounted to $0.8 million, $0.8 million and $1.2 million, respectively. Future minimum rental payments under noncancelable operating leases at December 31, 2002 are as follows (in thousands):

Year ending December 31,	
2003	$ 841
2004	200
2005	191
2006	169
2007	3
	$ 1,404

6. PARTNERS' CAPITAL

On July 26, 2002, the Partnership completed its initial public offering of 8,600,000 common units representing limited partner interests, at a price of $19.50 per common unit. Total proceeds from the sale of the 8,600,000 units were $167.7 million, before offering costs and underwriting commissions. Concurrent with the closing of this offering, PEG entered into a $425.0 million credit agreement with a syndicate of financial institutions led by Fleet National Bank, that provides for a five-year $200.0 million senior secured revolving credit facility and a seven-year $225.0 million senior secured term loan facility. On July 26, 2002, PEG borrowed $225.0 million under the term loan facility. The $200.0 million revolving credit facility is currently undrawn except for the letters of credit totaling $6.5 million at December 31, 2002. (See Note 7, Long-term Debt)

A summary of the proceeds received from these two transactions and the use of those proceeds is as follows (in thousands):

Proceeds received:		
Sale of common units	$	167,700
Borrowing under term loan facility		225,000
Total proceeds received	$	392,700
Use of proceeds from sale of common units:		
Underwriting discount	$	11,500
Professional fees and other offering costs (1)		4,900
Repayment of debt (1)		151,300
Total use of proceeds from the sale of common units	$	167,700
Use of proceeds from term loan facility:		
Debt issuance costs and related expenses	$	5,300
Repayment of debt		114,600
Distribution to General Partner		105,100
Total use of proceeds from term loan facility	$	225,000
Total use of proceeds	$	392,700

(1) Based upon the amount of professional fees and other offering costs, net proceeds from the sale of common units used to repay debt amounted to $151.3 million. The remaining outstanding debt balance of $2.4 million was repaid by PEG.

7. LONG-TERM DEBT

The Partnership's long-term debt obligations at December 31, 2001, shown below, were refinanced in July 2002 in connection with the Partnership's initial public offering of common units and its borrowing under new credit facilities:

		2001		2002
		(in thousands)		
Note payable to Citibank	$	176,400	$	
Note payable to Affiliate		4,933		
Senior secured revolving credit facility				
Senior secured term loan facility				225,000
Less current portion of long-term debt				
Total	$	181,333	$	225,000

	2001	2002

Payments due on the senior secured term loan during each of the five years subsequent to December 31, 2002 are as follows: (in thousands):

Year ending December 31,

2003	$
2004	
2005	1,125
2006	2,250
2007	2,250
Thereafter	219,375
Total	$ 225,000

A $200.0 million revolving credit facility is available for general partnership purposes, including working capital, letters of credit and distributions to unitholders and to finance future acquisitions, including the pending acquisition of the EPTC Assets (see Note 2, Pending Acquisition). The revolving credit facility has a borrowing sublimit of $45.0 million for working capital, letters of credit and partnership distributions to unitholders.

The revolving credit facility matures on July 26, 2007, at which time all outstanding amounts will be due and payable. The Partnership will be required to amortize amounts outstanding under the term loan on a quarterly basis at 1% per annum, with the first quarterly payment due September 2005. A 97% balloon payment will be due at maturity in July 2009.

PEG is the borrower under both the revolving credit facility and term loan, which are guaranteed by the Partnership and certain of PEG's operating subsidiaries. The revolving credit facility and the term loan facility are both fully recourse to PEG and the guarantors, but non-recourse to the General Partner. Obligations under the revolving credit facility and the term loan are secured by pledges of membership interests in and the assets of certain of PEG's operating subsidiaries.

Indebtedness under the revolving credit facility and term loan bear interest at the Partnership's option, at either (i) the base rate, which is equal to the higher of the prime rate as announced by Fleet National Bank or the Federal Funds rate plus 0.50% (each plus an applicable margin ranging from 0% to 0.50% for the revolving credit facility and ranging from 0.50% to 0.75% for the term loan) or (ii) LIBOR plus an applicable margin ranging from 1.25% to 2.50% for the revolving credit facility and ranging from 2.50% to 2.75% for the term loan. The applicable margins are subject to change based on the credit rating of the facilities or, if they are not rated, the credit rating of PEG. After the purchase of the EPTC Assets, the applicable margin will increase by a margin which ranges from 0.375% to 0.625% and will remain at that level for 270 days after the purchase or until we successfully conclude an equity offering, that reduces certain ratios to specified levels, whichever is earlier. PEG incurs a commitment fee which ranges from 0.25% to 0.50% per annum on the unused portion of the revolving credit facility. Under the credit agreement, PEG is prohibited from declaring dividends or distributions if any event of default, as defined in the credit agreement, occurs or would result from such declaration. In addition, the credit agreement contains certain financial covenants and covenants limiting the ability of PEG and certain of its subsidiaries to, among other things, incur or guarantee indebtedness, change ownership or structure, including consolidations, liquidations and dissolutions and

enter into a new line of business. At December 31, 2002, PEG and its subsidiaries were in compliance with all such covenants.

At December 31, 2002, the Partnership had letters of credit totaling $6.5 million, for PMT activities, which were supported by the Partnership's $200.0 million revolving credit facility.

8. RELATED PARTY TRANSACTIONS

ARCO owned a 26.5% ownership interest in PPS from May 1, 1999 through June 7, 2001 and was therefore a related party of the Partnership during this period. During this period, PPS entered into various agreements with ARCO under which ARCO provided operating services to the Partnership and leased facility space from the Partnership. The Partnership and ARCO also shared certain facilities that supported the operations of both companies. The cost of operating the shared facilities was allocated based on the percentage benefit obtained by both the Partnership and ARCO. The Partnership paid ARCO $0.1 million and $0.2 million during 2000 and 2001, respectively. The Partnership received $0.1 million and $0.2 million from ARCO during 2000 and 2001, respectively.

During 2002, PEG received a capital contribution from Anschutz of $8.8 million and paid distributions to Anschutz of $16.0 million prior to the initial public offering in July. Concurrent with the initial public offering, PEG paid a distribution of $105.1 million to Anschutz. Subsequent to the initial public offering, the Partnership paid quarterly distributions in respect of the third quarter 2002 to Anschutz of $4.3 million on its common units, subordinated units and 2% General Partner interest.

A subsidiary of Anschutz is a shipper on Line 2000 and is charged published tariff rates. The Partnership charged this subsidiary approximately $3.3 million, $0.2 million and $2.3 million during 2000, 2001 and 2002, respectively. This subsidiary entered into agreements with a third party to purchase crude oil, ship it on Line 2000, and sell it in the Los Angeles Basin. The amounts associated with these shipments included in accounts receivable were $0.6 million, $0.1 million and $0.4 million at December 31, 2000, 2001 and 2002, respectively. As an original sponsor of the Line 2000 project, Anschutz and its subsidiaries qualify for participating shipper tariff rates on the Line 2000 pipeline. Anschutz has designated its rights for participating shipper rates to the Partnership and other affiliates.

An affiliate of Anschutz is a shipper on AREPI pipeline and is charged published tariff rates. The Partnership charged this affiliate transportation fees of $1.2 million, $0.7 million and $0.1 million during 2000, 2001 and 2002, respectively. An affiliate of Anschutz is a shipper on RMP pipeline and is charged published tariff rates. The Partnership charged this affiliate transportation fees of $0.1 million during 2002.

Prior to April 1, 2002, Anschutz employed various personnel who worked directly on AREPI pipeline and provided other executive, accounting and administrative support to AREPI. Most of these employees continue to provide services to AREPI pipeline, but are now employed by the General Partner. For 2000, 2001 and 2002, Anschutz charged AREPI approximately $0.6 million, $0.6 million and $0.2 million for salaries of the pipeline related personnel and for various support services. On December 31, 2000 and 2001, AREPI declared and effected dividends to Anschutz of $3.6 million and $2.9 million, respectively. These dividends represented the amount of receivables due from Anschutz and its subsidiaries immediately prior to the dividends.

RMP serves as the contract operator for Anschutz Wahsatch Gathering System, Inc. ("AWGS"), a wholly owned subsidiary of Anschutz that owns a natural gas gathering system in Wyoming and Utah. AWGS reimburses RMP for the direct costs of operating the AWGS assets, such as the salary and benefit costs incurred by the direct assigned field operating and maintenance personnel related to AWGS operations. In addition, AWGS pays an annual management fee of $0.3 million to reimburse RMP for the portion of time spent by management and for other overhead services related to AWGS activities. As of December 31, 2002, $0.1 million was included in the accounts receivable of RMP on account of these services.

At December 31, 2001, Anschutz was providing letter-of-credit support for PMT activities totaling approximately $21.3 million. PMT reimbursed Anschutz for its cost of providing these letters of credit. Following the formation of the Partnership, such letters of credit were replaced by letters of credit under the Partnership's $200.0 million revolving credit facility.

In 2002, Anschutz paid certain expenses on behalf of RMP. Amounts charged in 2002 for reimbursement were $0.3 million, which is included in "due to related parties" of RMP at December 31, 2002. In 2002, Anschutz paid certain expenses on behalf of RPL. Amounts charged in 2002 for reimbursement were $0.4 million, which is included in "due to related parties" of RPL at December 31, 2002.

The Partnership does not have any employees. The General Partner employs approximately 215 employees who directly support the operations of the Partnership. All expenses incurred by the General Partner are charged to the Partnership. At December 31, 2002, amounts due to the General Partner for reimbursement of payroll and related costs amounted to $0.3 million.

In 2002, the Partnership began utilizing the financial accounting system owned and provided by Anschutz under a shared services arrangement. In addition, the Partnership utilizes the services of Anschutz's risk management personnel for acquiring the Partnership's insurance, and the Partnership's surety bonds are issued under Anschutz's bonding line. Out of pocket costs incurred by Anschutz for the benefit of the Partnership for computer consultants, insurance premiums and surety bond costs were reimbursed by the Partnership. Beginning January 2003, the Partnership will pay Anschutz a fee of $0.1 million per year for these services and continue to reimburse Anschutz for any out of pocket costs it incurs. The fixed annual fee includes all license, maintenance and employee costs associated with the Partnership's use of the financial accounting system.

In 2002, Anschutz provided office space to several employees of the Partnership at no cost to the Partnership. Beginning January 2003, the Partnership leased approximately 4,700 square feet of office space from an affiliate of Anschutz, for a term of five years at an initial annual cost of $0.1 million, the prevailing market rate for comparable space. Also beginning in 2003, the Partnership's trucking operation began hauling water for an Anschutz oil and gas subsidiary at rates equivalent to those charged to third parties.

9. 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 $5.2 million, $5.2 million and $3.3 million in 2000, 2001 and 2002, respectively.

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. The Partnership paid UPC rentals due under this agreement of $3.9 million, $4.0 million and $1.7 million in 2000, 2001 and 2002, respectively. Under the agreement the annual rental is to be adjusted every five years, in accordance with prescribed procedures, to reflect fair rental value. The first revision was to have been made effective as of April 1, 2002, but as of January 28, 2003, the parties have not completed the revision process. Accordingly, the rental that was paid for 2002 was an estimate, and is subject to subsequent adjustment. Phillip F. Anschutz, a director of the Partnership's General Partner and sole stockholder of Anschutz Company, the indirect parent of the Partnership's General Partner, is a director and the Non-Executive Vice Chairman of UPC.

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. The future minimum payments, as of December 31, 2002, under the Partnership's right-of-way agreements are presented below (in thousands) and reflect the Partnership's commitment for the next 15 years assuming the current right-of-way agreements will be renewed during the period. The annual amounts payable under right-of-way agreements subsequent to 2006 are subject to adjustments as described above as well as for the effects of inflation.

Years ending December 31:		
2003	$	2,864
2004		2,864
2005		2,861
2006		2,861
2007		2,861
Thereafter		12,914
Total	$	27,225

The Partnership has accrued an estimated liability of $0.4 million at December 31, 2002 related to costs it expects to incur related to title and easement work on the Line 63 system associated with the transfer of easements from ARCO to PPS.

10. LONG-TERM INCENTIVE PLAN

In July 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 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 General Partner, subject to approval by the Board of Directors. The 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 General Partner's Board of Directors also

reserve 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 Partnership has the option to either issue common units or pay the holder of the restricted units cash equal to the fair market value on the vesting date. The Partnership intends to issue common units rather than pay cash as the restricted units vest, and as such, accounts for the restricted unit plan as a fixed plan.

In December 2002, the General Partner granted 381,250 restricted units to certain key employees which vest over approximately two to five years from the date of grant. These units are subject to forfeiture if employment is terminated prior to vesting. The Partnership recognized $0.1 million of compensation expense associated with these grants in 2002. The fair market value of the restricted units associated with these grants was $7.5 million on the grant date.

In December 2002, the General Partner granted 50,000 unit options. The unit options were granted with an exercise price equal to the fair market value at the date of grant. The outstanding unit options have 10 year terms and vest approximately two years from the date of grant. At December 31, 2002, there were 50,000 unit options outstanding.

The per unit weighted average fair value of unit options granted in 2002 was $1.67 on the date of grant using the Black Scholes option-pricing model. The following assumptions were used to compute the weighted average fair market value of options granted:

Expected life of options	5 years
Risk free interest rates	2.7%
Estimated volatility	31.9%
Cash distribution yield	9.4%

The Partnership applies APB Opinion No. 25, "Accounting for Stock Issued to Employees," and, accordingly, no compensation expense has been recognized for its unit options in the financial statements. Had the Partnership determined compensation cost based on the fair value at the grant date for its unit options under SFAS No. 123, "Accounting for Stock-Based Compensation," net income and earnings per limited partner unit would not have been materially reduced for the year ended December 31, 2002.

Unit option activity during the year ended December 31, 2002 is as follows:

	Number of units	**Weighted-average exercise price**
Balance at January 1, 2002		
Granted	50,000	$ 19.50
Exercised		
Forfeited		
Balance at December 31, 2002	50,000	$ 19.50

At December 31, 2002, the exercise price and weighted-average remaining contractual life of outstanding options was $19.50 per unit and 9.7 years, respectively.

11. QUARTERLY FINANCIAL DATA (unaudited)

	Year ended December 31, 2001				
	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total**
	(in thousands)				
Net revenue	$ 17,045	$ 17,209	$ 20,736	$ 20,274	$ 75,264
Operating income	6,550	5,939	6,559	5,828	24,876
Net income	3,022	3,349	4,713	4,523	15,607

	Year ended December 31, 2002				
	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total**
	(in thousands)				
Net revenue	$ 26,816	$ 33,527	$ 32,234	$ 31,934	$ 124,511

	Year ended December 31, 2002				
Operating income	10,396	11,805	11,666	10,473	44,340
Net income	9,181	9,631	8,358	6,404	33,574
Net income per limited partner unit(1)			0.25	0.30	0.55

(1) Net income per limited partner unit for the third quarter 2002 and for 2002 total, is based on income for the period from July 26 through September 30, 2002 and July 26 through December 31, 2002, respectively

12. SEGMENT INFORMATION

As described in note 1, the Partnership operates in two business segments, its West Coast operations and its Rocky Mountain operations. Information regarding these two segments is as follows:

	West Coast	Rocky Mountains	Total
		(in thousands)	
Year Ended December 31, 2000			
Transportation revenue			
Unaffiliated customers	$ 63,157	$ 3,762	$ 66,919
Affiliates	3,324	1,176	4,500
Depreciation and amortization	11,248	625	11,873
Operating income(1)	29,710	4,586	34,296
Capital expenditures	3,378	109	3,487
Identifiable assets	357,107	8,904	366,011
Year Ended December 31, 2001			
Transportation revenue			
Unaffiliated customers	$ 60,835	$ 4,505	$ 65,340
Affiliates	246	650	896
Crude oil sales, net	9,028		9,028
Depreciation and amortization	10,887	481	11,368
Operating income(1)	25,976	3,034	29,010
Capital expenditures	5,637	177	5,814
Identifiable assets	345,060	27,119	372,179
Year Ended December 31, 2002			
Transportation revenue			
Unaffiliated customers	$ 62,054	$ 37,635	$ 99,689
Affiliates	2,339	325	2,664
Crude oil sales, net	22,158		22,158
Depreciation and amortization	11,229	4,690	15,919
Operating income(1)	37,766	15,196	52,962
Capital expenditures	3,051	2,949	6,000
Identifiable assets	353,151	133,887	487,038

(1) The following is a reconciliation of operating income as stated above to the statements of income as general and administrative expenses are not allocated among the West Coast and Rocky Mountain operations:

	2000	2001	2002
		(in thousands)	
Income Statement Reconciliation			
Operating income from above:			
West Coast Operations	$ 29,710	$ 25,976	$ 37,766
Rocky Mountain Operations	4,586	3,034	15,196
Operating income from above	32,496	29,010	52,962
Less: General and administrative	2,672	4,134	8,622
Operating income	31,624	24,876	44,340
Other income	357	467	516
Interest income	474	320	385
Interest expense	(18,115)	(10,056)	(11,667)
Net income	$ 14,340	$ 15,607	$ 33,574

13. EMPLOYEE BENEFIT PLAN

PPS sponsors a defined contribution 401(k) plan whereby eligible employees may contribute up to 18% of their annual compensation to the plan, subject to certain defined limits. PPS matches employee contributions up to 6% of the employee's annual compensation. Total employer contributions to the plan for 2000, 2001 and 2002 were $0.3 million, $0.3 million and $0.8 million, respectively.

14. COMMITMENTS AND CONTINGENCIES

On March 15, 2002, Sinclair Oil Corporation ("Sinclair") filed a complaint with the Wyoming Public Service Commission ("WPSC") alleging that RMP's common stream rules and specifications and RMP's refusal to prohibit certain types of crude oil diluents from the common stream, all in respect of the Big Horn segment of the Western Corridor system, are adverse to Sinclair and the public interest. A hearing on Sinclair's complaint was held by the WPSC in October 2002, and briefs were filed by the parties in January 2003. In general, Sinclair is seeking an order from the WPSC requiring RMP to segregate certain crude oil types that are objectionable to Sinclair from the common stream. No decision has been issued by the WPSC. While the Partnership cannot predict the outcome of this dispute, this matter is not expected to have a material adverse effect on the Partnership's financial position, results of operations or liquidity.

On March 19, 2002, RMP filed revised tariffs that reduced the rates charged for interstate transportation service on the Western Corridor system. On April 15, 2002, Sinclair filed a complaint with the FERC challenging these rates. In its complaint, Sinclair alleges that the reduced rates exceed just and reasonable levels. RMP filed a general denial of Sinclair's allegations, as well as a motion for dismissal of Sinclair's complaint and, alternatively, a motion asking the FERC to hold Sinclair's complaint in abeyance pending the FERC's decision on an application for market-based rates, which, if granted, would allow RMP to set its tariff rates in response to competitive forces, rather than by reference to cost of service. Without ruling explicitly on either of RMP's motions, the FERC, in February 2003, ordered that a hearing be held to determine the issues raised by Sinclair's complaint. RMP has filed a motion for rehearing of that order. While the Partnership cannot predict the outcome of this dispute, this matter is not expected to have a material adverse effect on the Partnership's financial position, results of operations or liquidity.

The application for market based rates referenced in the preceding paragraph was filed by RMP on July 22, 2002. Protests to the application for market-based rates were filed with the FERC by Sinclair, Tesoro Refining and Marketing Company, ConocoPhillips and Chevron Products Company. These protests variously allege that the application incorrectly defined the relevant geographic and product markets and that, if such markets are properly defined, the Partnership should be found to have market power in those markets. The FERC has issued no rulings in response to this application. While being granted the right to set tariff rates for the Western Corridor on the basis of market considerations, rather than cost of service, would give RMP greater convenience and a desirable degree of pricing flexibility and responsiveness, a failure to prevail on its application, in whole or in part, would not be expected to have a material adverse effect on the Partnership's financial position, results of operations or liquidity.

The Partnership is subject to numerous federal, state and local laws which regulate the discharge of materials into the environment or that otherwise relate to the protection of the environment. The Partnership currently has an environmental remediation liability resulting from the acquisition of

ARCO's interst in PPS in 2001. The accrued liability was $2.6 million at December 31, 2002 and was classified in the consolidated balance sheets within "other liabilities." However, the total 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 parties.

The Partnership is involved in various other litigation and claims arising out of operations in the normal course of business, however, the Partnership is not currently a party to any legal or regulatory proceedings the resolution of which the Partnership expects to have a material adverse effect on its business, financial position, results of operations or liquidity.

15. SUBSEQUENT EVENT

On January 20, 2003, the Partnership declared a cash distribution of $0.4625 per limited partner unit, payable on February 14, 2003 to unitholders of record as of January 31, 2003.