PACIFIC ENERGY PARTNERS LP
Form 10-Q
May 05, 2004

Use these links to rapidly review the document
PACIFIC ENERGY PARTNERS, L.P. FORM 10-Q TABLE OF CONTENTS

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

ý **Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the quarterly period ended March 31, 2004

OR

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

For the transition period from to
Commission File Number 1-313345

PACIFIC ENERGY PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

DELAWARE	**68-0490580**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

5900 Cherry Avenue
Long Beach, CA 90805-4408
(Address of principal executive offices)

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

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

There were 18,641,763 of the registrant's Common Units and 10,465,000 of the registrant's Subordinated Units outstanding at March 31, 2004.

PACIFIC ENERGY PARTNERS, L.P.

FORM 10-Q
TABLE OF CONTENTS

PART I. FINANCIAL INFORMATION

ITEM 1. Financial Statements

PACIFIC ENERGY PARTNERS, L.P. (Note 1)
CONDENSED CONSOLIDATED BALANCE SHEETS

	March 31, 2004	December 31, 2003
	(in thousands) (unaudited)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 41,832	$ 9,699
Crude oil sales receivable	28,210	33,766
Transportation and storage accounts receivable	16,152	16,828
Crude oil inventory	5,267	2,272
Spare parts inventory	1,644	1,644
Prepaid expenses	3,319	4,182
Other	650	405
Total current assets	97,074	68,796
Property and equipment, net	565,285	567,954
Investment in Frontier (note 4)	6,897	6,886
Other assets	16,284	6,567
	$ 685,540	$ 650,203
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 12,825	$ 11,506
Accrued crude oil purchases	25,621	31,602
Due to related parties (note 7)	736	580
Derivatives liability current portion	5,535	4,986
Other	1,121	1,317
Total current liabilities	45,838	49,991
Long-term debt (note 5)	225,000	298,000
Derivatives liability	4,309	622
Other liabilities	6,523	6,523
Total liabilities	281,670	355,136
Commitments and contingencies (note 9)		
Partners' capital (note 6):		
Common unitholders (18,641,763 and 14,441,763 units outstanding at March 31, 2004 and December 31, 2003, respectively)	358,756	246,952
Subordinated unitholders (10,465,000 units outstanding at March 31, 2004 and December 31, 2003)	47,229	49,010
General Partner interest	6,332	3,975
Undistributed employee long-term incentive compensation	1,397	738

	March 31, 2004	December 31, 2003
Accumulated other comprehensive loss	(9,844)	(5,608)
Net partners' capital	403,870	295,067
	$ 685,540	$ 650,203

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. (Note 1)
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended March 31, 2004	Three Months Ended March 31, 2003
	(in thousands, except per unit amounts) (unaudited)	
Pipeline transportation revenue	$ 24,727	$ 25,320
Storage and terminaling revenue	10,123	
Crude oil sales, net of purchases of $81,115 and $86,652 for the three months ended March 31, 2004 and 2003	4,812	5,630
Net revenue before operating expenses	39,662	30,950
Expenses:		
Operating	18,917	12,648
Transition costs		397
General and administrative	3,854	3,982
Depreciation and amortization	5,242	4,181
	28,013	21,208
Share of net income of Frontier	393	341
Operating income	12,042	10,083
Other income	142	35
Interest income	19	56
Interest expense	(4,126)	(4,046)
Net income	$ 8,077	$ 6,128
Net income for the general partner interest	$ 162	$ 123
Net income for the limited partner interests	$ 7,915	$ 6,005
Basic net income per limited partner unit	$ 0.32	$ 0.29
Diluted net income per limited partner unit	$ 0.31	$ 0.29
Weighted average limited partner units outstanding:		
Basic	24,999	20,930
Diluted	25,149	21,000

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. (Note 1)
CONDENSED CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL

	Limited Partner Units		Limited Partner Amounts					
	Common	Subordinated	Common	Subordinated	General Partner Interest	Undistributed Employee Long-Term Incentive Compensation	Accumulated Other Comprehensive Loss	Total
					(in thousands) (unaudited)			
Balance, December 31, 2003	14,442	10,465	$ 246,952	$ 49,010	$ 3,975	$ 738	$ (5,608)	$ 295,067
Net income			4,594	3,321	162			8,077
Distribution to partners			(7,040)	(5,102)	(248)			(12,390)
Issuance of common units, net of fees and offering expenses (note 6)	4,200		114,250					114,250
General partner contribution related to issuance of common units (note 6)					2,443			2,443
Undistributed employee compensation under long-term incentive plan						659		659
Change in fair value of hedging derivatives							(4,236)	(4,236)
Balance, March 31, 2004	18,642	10,465	$ 358,756	$ 47,229	$ 6,332	$ 1,397	$ (9,844)	$ 403,870

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. (Note 1)
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three Months Ended March 31, 2004	Three Months Ended March 31, 2003
	(in thousands) (unaudited)	
Net income	$ 8,077	$ 6,128
Change in fair value of hedging derivatives	(4,236)	(861)
Comprehensive income	$ 3,841	$ 5,267

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. (Note 1)
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended March 31, 2004	Three Months Ended March 31, 2003
	(in thousands) (unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 8,077	$ 6,128
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	5,242	4,181
Amortization of debt issue costs	311	270
Non-cash portion of employee compensation under long-term incentive plan	659	1,034
Share of net income of Frontier	(393)	(341)
Distributions from Frontier, net	289	998
	14,185	12,270
Net changes in operating assets and liabilities:		
Crude oil sales receivable	5,556	(6,616)
Transportation and storage accounts receivable	676	(2,589)
Other current assets and liabilities	(2,417)	(505)
Accounts payable and other accrued liabilities	1,319	(1,780)
Accrued crude oil purchases	(5,981)	5,202
Other non-current assets and liabilities		(88)
	(847)	(6,376)
NET CASH PROVIDED BY OPERATING ACTIVITIES	13,338	5,894
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to property and equipment	(2,413)	(560)
Acquisitions	(9,920)	
Other		47
NET CASH USED IN INVESTING ACTIVITIES	(12,333)	(513)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of common units, net of fees and offering expenses	114,250	
Capital contributions from the general partner	2,443	
Proceeds from note payable to bank	16,500	
Repayment of long-term debt	(89,500)	
Deferred financing costs	(175)	
Distributions to partners	(12,390)	(9,878)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	31,128	(9,878)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	32,133	(4,497)
CASH AND CASH EQUIVALENTS, beginning of reporting period	9,699	23,873

	Three Months Ended March 31,	
CASH AND CASH EQUIVALENTS, end of reporting period	$ 41,832	$ 19,376
Supplemental disclosures:		
Cash paid for interest	$ 4,187	$ 3,860
Non-cash financing and investing activities:		
Change in fair value of interest rate hedging derivatives	$ (4,236)	$ (861)

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

March 31, 2004

(Unaudited)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

On July 26, 2002, Pacific Energy Partners, L.P. and its subsidiaries (the "Partnership") completed an initial public offering of common units representing limited partner interests. The Partnership, which was formed by The Anschutz Corporation ("TAC") in February 2002, and its subsidiaries are engaged principally in the business of gathering, transporting, storing and distributing crude oil and other dark products in California and the Rocky Mountain region. Revenue is generated primarily by charging tariff rates for transporting crude oil on the Partnership's pipelines and by leasing capacity in its storage facilities. The Partnership also buys, blends and sells crude oil, activities that are complementary to the Partnership's pipeline transportation business. The Partnership's business operations are organized into two regional operating units: West Coast operations and Rocky Mountain operations.

The Partnership owns 100% of Pacific Energy Group LLC ("PEG"), whose subsidiaries consist of: (i) Pacific Pipeline System LLC ("PPS"), owner of Line 2000 and the Line 63 system, (ii) Pacific Terminals LLC ("PT"), owner of the Pacific Terminals storage and distribution system, (iii) Pacific Marketing and Transportation LLC ("PMT"), owner of the PMT gathering and blending system, (iv) Rocky Mountain Pipeline System LLC ("RMPS"), owner of the Western Corridor system, the Salt Lake City Core system and AREPI pipeline and (v) Ranch Pipeline LLC ("RPL"), owner of a 22.22% partnership interest in Frontier Pipeline Company ("Frontier"). On January 1, 2004, Anschutz Ranch East Pipeline LLC, which had been a wholly-owned subsidiary of PEG, was merged into RMPS. PPS, PT and PMT comprise the West Coast segment. RMPS and RPL comprise the Rocky Mountain segment. Certain costs of PEG are also included in each segment.

The general partner of the Partnership is Pacific Energy GP, Inc. ("General Partner"), a wholly owned, indirect subsidiary of TAC. In addition to the 2% general partner interest held by the General Partner, TAC also owns 10,465,000 subordinated units of the Partnership.

On July 31, 2003, PT completed the acquisition of the storage and pipeline distribution assets for a total purchase price of $173 million. The purchase was funded through $90 million of proceeds from the issuance of additional common units on August 25, 2003, and borrowings under the Partnership's revolving credit facility. The consolidated financial statements reflect the ownership and results of operations of PT for the period from the date of acquisition.

The unaudited condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America for interim financial reporting and with Securities and Exchange Commission ("SEC") regulations. Accordingly, these statements have been condensed and do not include all of the information and footnotes required for complete financial statements. These statements involve the use of estimates and judgments where appropriate. In the opinion of management, all adjustments, consisting of normal recurring accruals considered necessary for a fair presentation, have been included. The results of operations for the three months ended March 31, 2004 and 2003 are not necessarily indicative of the results of operations for the full year. The financial data for the three months ended March 31, 2004 and 2003 is derived from the Partnership's unaudited condensed consolidated financial statements. The financial data as of December 31, 2003 is derived from the Partnership's audited consolidated financial statements. All significant intercompany balances and transactions have been eliminated during the consolidation process.

These financial statements should be read in conjunction with the Partnership's audited consolidated financial statements and notes thereto included in the Partnership's annual report on Form 10-K for the year ended December 31, 2003.

Description of Business

West Coast Segment

The Partnership's West Coast operations are comprised of the following assets, all of which are operated and owned 100% by the Partnership:

PPS owns and operates two crude oil pipelines, Line 2000 and the Line 63 system. Line 2000, which began operation in January 1999, consists of a 130-mile, insulated crude oil pipeline with a permitted annual throughput capacity of 130,000 barrels per day ("bpd"). It is an intrastate common carrier 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.

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 156 miles of gathering lines, 60 miles of distribution lines and 22 storage tanks with a total of approximately 1.2 million barrels of storage capacity. Most of the storage assets are located in the San Joaquin Valley and are primarily used to facilitate the transportation of crude oil on the Partnership's pipelines.

PT was formed in February 2002 in connection with the acquisition on July 31, 2003 of the Pacific Terminals storage distribution system, for an all-in purchase price of approximately $173.0 million. The Pacific Terminals storage and distribution system consists of 70 miles of distribution pipelines in active service and 34 storage tanks with a total of approximately 9.0 million barrels of storage capacity. Of this total capacity, approximately 6.7 million barrels are in active commercial service, 0.4 million barrels are used primarily for "throughput" to other tanks and do not generate revenue independently, approximately 1.7 million barrels are idle but could be reconditioned and brought into service, and approximately 250,000 barrels are in displacement oil service. The purchase of these assets resulted in negative goodwill of $20.5 million, which was allocated proportionately to reduce property and equipment and displacement oil and minimum tank inventories of PT.

PMT's assets include a proprietary crude oil gathering and blending pipeline system located in the San Joaquin Valley. The PMT system consists of 103 miles of gathering pipelines and six storage and blending facilities with a total of approximately 250,000 barrels of storage capacity and up to 65,000 bpd of blending capacity. PMT is interconnected to our Line 63 system. PMT buys, blends and sells crude oil, activities that are complementary to the Partnership's pipeline transportation business.

Rocky Mountain Segment

The Partnership's Rocky Mountain operations are comprised of the following assets, which form an integrated pipeline network:

RMPS pipeline and related assets include the Western Corridor system, the Salt Lake City Core system and AREPI pipeline. The Western Corridor system is an interstate and intrastate common carrier crude oil pipeline system consisting of 1,012 miles of pipelines extending from dual origination points at the Canadian Border. The Western Corridor system consists of three contiguous crude oil pipelines: Glacier pipeline, Beartooth pipeline and Big Horn pipeline. The Partnership owns various undivided interests in each of these three pipelines, which gives the Partnership rights to a specified portion of each pipeline's throughput capacity, and operates the Beartooth and Big Horn pipelines.

The Salt Lake City Core system is also an interstate and intrastate common carrier crude oil pipeline system which consists of 913 miles of crude oil pipelines, 209 miles of gathering pipelines and 29 storage tanks with a total of approximately 1.4 million barrels of storage capacity. The Partnership owns and operates 100% of the Salt Lake City Core system.

AREPI pipeline is an interstate common carrier crude oil pipeline consisting of a 42 mile crude oil pipeline and three storage tanks with a total of approximately 0.1 million barrels of storage capacity. The Partnership owns and operates 100% of the AREPI pipeline.

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

Management Estimates

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

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

Income Taxes

No provision for federal or state income taxes related to operations is included in the accompanying condensed 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 its 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 Partnership's First Amended and Restated Agreement of Limited Partnership, as amended. Individual unitholders have different investment bases depending upon the timing and price of acquisition of partnership units. Further, each unitholder's tax accounting, which is partially dependent upon the unitholder's tax position, differs from the accounting followed in the condensed 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.

Upon completion of the Rangeland and MAPL transactions described in "Note 2 Acquisition Agreements", the Partnership's Canadian subsidiaries will be taxable entities in Canada and will be subject to Federal and provincial income taxes. In addition, monies repatriated from Canada into the U.S. may be subject to withholding taxes. Individual unitholders will generally have no responsibility to file Canadian tax returns.

Net Income per Unit

Basic net income per limited partner unit is determined by dividing net income after deducting the amount allocated to the general partner interest, by the weighted average number of outstanding limited partner units.

Diluted net income per limited partner unit is calculated in the same manner as basic net income per limited partners unit above, except that the weighted average number of outstanding limited partner units is increased to include the dilutive effect of outstanding options and restricted units by application of the treasury stock method. Following is a reconciliation of the basic weighted average outstanding limited partner units to diluted weighted average limited partner units.

	Three Months Ended March 31,	
	2004	2003
	(in thousands) (unaudited)	
Basic weighted average limited partner units	24,999	20,930
Effect of restricted units	134	68
Effect of options	16	2
Diluted weighted average limited partner units	25,149	21,000

Reclassifications

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

Accounting Pronouncements

In December 2003, the FASB issued FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51 (FIN46R).* FIN46R requires companies to evaluate variable interest entities for specific characteristics to determine whether additional consolidation and disclosure requirements apply. The transition guidance requires the application of FIN 46R to all special-purpose entities (SPEs) no later than the end of the first reporting period ending after December 15, 2003 and immediately to all entities created after January 31, 2003. The adoption of FIN 46R did not have any impact on the Partnership's consolidated financial statements.

2. ACQUISITION AGREEMENTS

Pending Rangeland Acquisition

On February 23, 2004, the Partnership entered into a definitive share purchase and sale agreement to acquire the Rangeland Pipeline System from BP Canada Energy Company. The Rangeland Pipeline System, which is located in the province of Alberta, Canada, consists of Rangeland Pipeline Company, Rangeland Marketing Company and Aurora Pipeline Company Ltd. The acquisition price for the Rangeland Pipeline System is $130.0 million (Canadian) plus an estimated $26.0 million (Canadian) for linefill, working capital, transaction costs and transition capital expenditures. At an exchange rate of $1 U.S. to $1.31 Canadian, as of March 31, 2004, the total purchase price would be approximately U.S. $119 million. Closing of the transaction is expected in May 2004 following fulfillment of customary closing conditions. During the quarter ended March 31, 2003, the Company made a deposit of $9.7 million related to the acquisition of the Rangeland Pipeline System, which is recorded in "Other assets" on the accompanying condensed consolidated balance sheets.

MAPL Letter of Intent

On February 24, 2004, the Partnership entered into a non-binding letter of intent to purchase the Mid Alberta Pipeline ("MAPL") assets, also in Alberta, from Imperial Oil Resources. This transaction is subject to completion of a definitive purchase and sale agreement and fulfillment of such closing conditions as may be included in the purchase and sale agreement. The transaction is expected to close in the second quarter of 2004.

3. DEVELOPMENT PROJECT

In the first quarter of 2004, the Partnership completed a feasibility study with respect to the development of a new deepwater petroleum import terminal and related storage and pipeline distribution facilities to handle marine receipts of crude oil and feedstocks in the Port of Los Angeles (the "Pier 400 Project") and is proceeding with the next phase of development. The Pier 400 Project will be subject to environmental permitting requirements and will require approvals from a variety of governmental agencies, including the Board of Harbor Commissioners, various agencies of the City of Los Angeles and the Los Angeles City Council. The Partnership also entered into a project development agreement with two subsidiaries of Valero Energy Corporation (the "Valero Agreement") that defined the project facilities to be constructed by the Partnership, and which is subject to the satisfaction of various conditions, including completion of a mutually satisfactory terminalling services agreement with a 30 year, 50,000 bpd volume commitment from Valero to support the project. In addition, the Partnership and the Port of Los Angeles have identified several possible sites for construction of storage facilities by the Partnership and have agreed to begin the review process required by the California Environmental Quality Act ("CEQA"). Completion of construction and start up of the project is targeted for late 2006. Through March 31, 2004, the Partnership capitalized $5.6 million related to the project.

4. INVESTMENT IN FRONTIER PIPELINE COMPANY

RPL owns a 22.22% partnership interest in Frontier, which is accounted for by the equity method of accounting. Under the equity method, the investment is initially recorded at cost and subsequently adjusted to recognize the investor's share of distributions and net income or loss of the investee as they occur. Recognition of any such loss is generally limited to the total of the investor's investment in, advances to, commitments and guarantees for the investee.

The summarized balance sheets of Frontier at March 31, 2004 and December 31, 2003, and the statements of income for the three months ended March 31, 2004 and 2003 are presented below:

Balance Sheets

	March 31, 2004	December 31, 2003
	(in thousands) (unaudited)	
Current assets	$ 2,025	$ 2,013
Property and equipment, net	8,844	8,900
Other assets	1	1
	$ 10,870	$ 10,914
Current liabilities	$ 5,834	$ 6,313
Other liabilities	2,124	2,159
Partners' capital	2,912	2,442
	$ 10,870	$ 10,914

Statements of Income

	Three Months Ended March 31, 2004	Three Months Ended March 31, 2003
	(in thousands) (unaudited)	
Revenue	$ 2,601	$ 2,130
Net income	$ 1,771	$ 1,537

The unamortized portion of the excess cost over the Partnership's share of net assets of Frontier is $6.8 million and $6.9 million at March 31, 2004 and December 31, 2003, respectively. This excess cost over the Partnership's share of net assets represents the difference between the historical cost and the fair value of property and equipment at acquisition dates. The Partnership is amortizing this excess cost over the life of the related property and equipment.

5. LONG-TERM DEBT

The Partnership's long-term debt obligations at March 31, 2004 and December 31, 2003 are shown below:

	March 31, 2004	December 31, 2003
	(in thousands) (unaudited)	
Senior secured revolving credit facility	$	$ 73,000
Senior secured term loan facility	225,000	225,000
Total	225,000	298,000
Less current portion		
Long-term debt	$ 225,000	$ 298,000

PEG is the borrower under both the revolving credit facility and the term loan, which are guaranteed by the Partnership and certain of PEG's operating subsidiaries. The revolving credit facility and term loan 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 PEG and certain of PEG's operating subsidiaries.

The revolving credit facility is a $200.0 million facility that is available for general partnership purposes, including working capital, letters of credit and distributions to unitholders, and to finance future acquisitions. Borrowings under the revolving credit facility are limited by various financial covenants in the credit agreement. The revolving credit facility also has a borrowing sublimit of $45.0 million for working capital, letters of credit and partnership distributions to unitholders. At March 31, 2004, there were no borrowings under the revolving credit facility and no letters of credit were outstanding as of that date.

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 at 1% per annum, payable on a quarterly basis with the first payment due September 2005. A 97% balloon payment on the term loan will be due at maturity in July 2009.

Effective December 12, 2003, PEG and its lenders amended the interest rates and other fees under the credit facilities. Subject to certain limited exceptions, indebtedness under the revolving credit facility and the term loan now bear interest at PEG'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 0.25% for the term loan) or (ii) LIBOR plus an applicable margin ranging from 0.75% to 2.00% for the revolving credit facility and ranging from 2.00% to 2.25% 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. They may also increase for periods of time after significant acquisitions until additional equity is raised by the Partnership.

PEG incurs a commitment fee which ranges from 0.125% to 0.375% 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 March 31, 2004, PEG and its subsidiaries that are guarantors under the credit agreement were in compliance with all such covenants.

6. PARTNERS' CAPITAL

On March 30, 2004, the Partnership issued and sold 4,200,000 common units in an underwritten public offering at a price of $28.50. The common units sold in the offering were registered pursuant to the registration statement on SEC Form S-3 filed on August 1, 2003. Net proceeds from the offering, including the general partner's contribution of $2.4 million, totaled approximately $116.7 million after deducting underwriting fees and offering expenses of $5.4 million. The Partnership repaid approximately $10 million in borrowings under its U.S. revolving credit facilities which was incurred in the first quarter of 2004 to fund a deposit on the Rangeland acquisition and intends to use approximately $76 million of the net proceeds to fund a portion of the aggregate purchase price of the Rangeland and Mid Alberta pipeline acquisitions. Pending the use of this portion of the net proceeds for the Rangeland and Mid Alberta Pipeline acquisitions, and together with the balance of the net proceeds, the Partnership repaid the remaining $79.5 million of borrowings outstanding under its U.S. revolving credit facility and added to its cash balance.

In addition to using $86 million of net proceeds to fund a portion of the Rangeland and Mid Alberta pipeline acquisitions, the Partnership is effectively utilizing the remaining $31 million in net proceeds as follows: (i) $8 million to repay borrowings incurred in the second half of 2003 to fund growth capital expenditures, (ii) $10 million to repay borrowings under its U.S. revolving credit facility to increase availability under that facility to fund 2004 growth capital projects including pre-construction development activities for the Pier 400 Project and establishing a new connection between AREPI pipeline and the Salt Lake City Core System and other growth capital expenditures, and (iii) $13 million to repay borrowings to increase its available borrowing capacity to fund future growth capital projects.

Subsequent to the end of the quarter, on April 12, 2004, the underwriters exercised a portion of the over-allotment option granted in connection with the offering of common units on March 30, 2004 and purchased an additional 425,000 common units from the Partnership at a price of $28.50 per unit to cover over allotments. Including the related capital contribution of the General Partner of $247,000, the partnership received net proceeds of $11.8 million after underwriting fees. The Partnership has temporarily added these net proceeds to its cash balance. Following the closing of the Canadian acquisitions and associated re-borrowings under its U.S. revolving credit facility, the Partnership will in effect use the $12 million in net proceeds from the exercise of the overallotment option to reduce the balance outstanding under its revolving credit facility pending future investment in capital projects.

7. RELATED PARTY TRANSACTIONS

In the ordinary course of its operations, the Partnership engages in various transactions with TAC and its affiliates. These transactions, which are more thoroughly described below, are summarized in the following table for the three months ended March 31, 2004 and 2003:

	Three Months Ended March 31,	
	2004	**2003**
	(in thousands) (unaudited)	
Pipeline transportation revenue:		
The Anschutz Corporation and affiliates	$ 169	$ 641
General and administrative expense:		
The Anschutz Corporation and affiliates	$ 49	$ 45

Related party balances at March 31, 2004 and December 31, 2003 were as follows:

	March 31, 2004	December 31, 2003
	(in thousands) (unaudited)	
Amounts included in accounts receivable:		
The Anschutz Corporation and affiliates	$ 94	$ 155
Amounts included in due to related parties:		
The Anschutz Corporation and affiliates	$ 25	$
Pacific Energy GP, Inc.	711	580
Total	$ 736	$ 580
Amounts included in undistributed long-term incentive compensation:		
Pacific Energy GP, Inc.	$ 1,397	$ 738

Revenue from Related Parties

A subsidiary of TAC was a shipper on Line 2000 and was charged the published tariff rates applicable to "participating shippers" until March 31, 2003, when an agreement between the TAC subsidiary and a third party, the performance of which required the TAC subsidiary to ship on Line 2000, was assigned to PMT for consideration equal to the value of inventory that was transferred to PMT. In addition, a subsidiary of TAC is a shipper on RMPS's pipeline systems and the AREPI pipeline and is charged published tariff rates.

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

RMPS also receives a management fee from Frontier Pipeline in connection with time spent by RMPS management and for other services related to the pipeline's activities. RMPS received $0.2 million for each of the three months ended March 31, 2004 and 2003.

Expenses Paid to Related Parties

General and Administrative Expense: In 2002, the Partnership began utilizing the financial accounting system owned and provided by TAC under a shared services arrangement. In addition, the Partnership from time to time utilizes the services of TAC's risk management personnel for acquiring the Partnership's insurance, and the Partnership's surety bonds are issued under TAC's bonding line. Beginning January 2003, TAC began charging the Partnership a fee of $0.1 million per year for these services and continues to charge the Partnership 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.

Beginning January 2003, the Partnership leased approximately 4,700 square feet of office space from an affiliate of TAC, for a term of five years at an initial annual cost of $0.1 million.

Cost Reimbursements: The Partnership does not have any employees. The General Partner, which is a wholly owned indirect subsidiary of TAC, employed approximately 260 individuals at March 31, 2004 who directly supported the operations of the Partnership. All expenses incurred by the General Partner on behalf of the Partnership are charged to the Partnership.

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

8. SEGMENT INFORMATION

The Partnership's business and operations are organized into two regional operating units: West Coast operations and Rocky Mountain operations. The West Coast operations include PPS, PMT, and PT (for the period from July 31, 2003 to March 31, 2004). Rocky Mountain operations include RMPS and RPL. The reporting units comprising each segment have been aggregated to reflect how the assets are operated and managed. General and administrative costs, which consist of executive management, accounting and finance, human resources, information technology, investor relations, legal, and marketing and business development, are not allocated to the individual segments. Information regarding these two operating units is summarized below:

	West Coast Operations	Rocky Mountain Operations	Intersegment and Intrasegment Eliminations	Total
		(in thousands) (unaudited)		
Three months ended March 31, 2004				
Segment revenue:				
Pipeline transportation revenue	$ 15,691	$ 10,543	$ (1,507)	$ 24,727
Storage and distribution revenue(1)	10,223		(100)	10,123
Crude oil sales, net of purchases(2)	4,812			4,812
Net revenue	30,726	10,543		39,662
Expenses:				
Operating	14,706	5,818	(1,607)	18,917
Transition costs				
Depreciation and amortization	3,765	1,477		5,242
Total expenses	18,471	7,295		24,159
Share of net income of Frontier		393		393
Operating income(3)	$ 12,255	$ 3,641		$ 15,896
Identifiable assets(4)	$ 511,254	$ 123,837		$ 635,091
Capital expenditures	$ 1,122	$ 1,291		$ 2,413
Three months ended March 31, 2003				
Segment revenue:				
Pipeline transportation revenue	$ 17,334	$ 9,399	$ (1,413)	$ 25,320
Storage and distribution revenue(1)				
Crude oil sales, net of purchases(2)	5,630			5,630
Net revenue	22,964	9,399		30,950
Expenses:				
Operating	9,419	4,642	(1,413)	12,648
Transition costs		397		397
Depreciation	2,822	1,359		4,181
Total expenses	12,241	6,398		17,226

	West Coast Operations	Rocky Mountain Operations	Intersegment and Intrasegment Eliminations	Total
Share of net income of Frontier		341		341
Operating income(3)	$ 10,723	$ 3,342		$ 14,065
Identifiable assets(4)	$ 343,038	$ 131,798		$ 474,836
Capital expenditures	$ 370	$ 190		$ 560

(1) Includes the operations of the PT storage and distribution system, which PT acquired on July 31, 2003.

(2) The above amounts are net of purchases of $81,115 and $86,652 for 2004 and 2003, respectively.

(3)
The following is a reconciliation of operating income as stated above to the statements of income:

	Three Months Ended	
	March 31, 2004	March 31, 2003
	(in thousands) (unaudited)	
Income Statement Reconciliation		
Operating income from above:		
West Coast Operations	$ 12,255	$ 10,723
Rocky Mountain Operations	3,641	3,342
Operating income	15,896	14,065
Less: General and administrative	3,854	3,982
Operating income	12,042	10,083
Other income	142	35
Interest income	19	56
Interest expense	(4,126)	(4,046)
Net income	$ 8,077	$ 6,128

(4)
Identifiable segment assets do not include assets related to the Partnership's corporate activity. As of March 31, 2004 and 2003, corporate related assets were $50,449 and $12,235 respectively.

9. COMMITMENTS AND CONTINGENCIES

On March 15, 2002, Sinclair Oil Corporation ("Sinclair") filed a complaint with the Wyoming Public Service Commission ("WPSC") alleging that RMPS's common stream rules and specifications and RMPS's refusal to prohibit certain types of crude oil diluents from the sour crude oil common stream, all in respect of the Big Horn segment of the Western Corridor system, are adverse to Sinclair and the public interest. On October 21, 2003, the WPSC issued a decision adverse to RMPS, the full impact to RMPS of which could not be determined in the absence of further clarification from the WPSC. On March 9, 2004, after RMPS filed a motion for a rehearing with the WPSC, RMPS entered into a stipulation and agreement with Sinclair, Conoco Pipe Line Company and ConocoPhillips Company that, subject to the satisfaction of various conditions, including the approval of various tariff provisions by shippers and the Federal Energy Regulatory Commission ("FERC"), will provide a resolution of Sinclair's complaint at no material cost to RMPS. Regardless of whether the conditions to the effectiveness of the stipulation and agreement are satisfied, the Partnership does not expect this matter to have a material adverse effect on its consolidated financial position or results of operations.

On February 18, 2004, a decision was issued by the FERC finding Frontier liable to Big West Oil Company and Chevron Products Company (the "Complainants") for tariff reparations in the aggregate amount of approximately $4.2 million plus interest which, as of December 31, 2003, was approximately $1 million. The Partnership's earnings for 2003 reflected a charge for its 22.22% share of this total amount. In reaching its decision, the FERC ruled that certain joint rates in which Frontier participated were unjust and unreasonable, but ruled in favor of Frontier on the issue of whether Complainants were entitled to reparations for volumes shipped by third parties. Frontier and the Complainants have each filed motions for rehearing asking the FERC to reconsider those issues determined adversely to them, respectively. In addition, the Complainants have appealed the issue determined adversely to them to the U.S. Court of Appeals. If the third party volume issue being appealed by the Complainants is reversed, the total reparations award would, in the absence of a reversal of any other issues, increase by approximately $740,000, plus interest thereon. Of this amount, 22.22% would be borne by the

Partnership. The Partnership cannot predict the outcome of the pending motions for rehearing or appeal, but it does not expect this matter to have a material adverse effect on its consolidated financial position or results of operations.

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 environmental remediation liabilities of $5.5 million and right-of-way liabilities of $1.0 million, at March 31, 2004 resulting from various acquisitions which is classified in the condensed consolidated balance sheets within "other liabilities." The actual future costs for environmental remediation activities will depend on, among other things, the identification of any additional sites, the determination of the extent of the contamination at each site, the timing and nature of required remedial actions, the technology available and required to meet the various existing legal requirements, the nature and extent of future environmental laws, inflation rates and the determination of the Partnership's liability at multi-party sites, if any, in light of uncertainties with respect to joint and several liability, and the number, participation levels and financial viability of other potentially responsible parties.

The Partnership is involved in various other regulatory disputes, litigation and claims arising out of its 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 it could expect to have a material adverse effect on its business, financial condition or results of operations.

10. SUBSEQUENT EVENT

On April 7, 2004, the Partnership declared a cash distribution of $0.4875 per limited partner unit, payable on May 14, 2004, to unitholders of record as of April 30, 2004.

ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

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

Forward-Looking Statements

The information in this quarterly report on Form 10-Q contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, and Section 21E of the Securities Exchange Act of 1934. 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 and uncertainties. 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 quarterly report on Form 10-Q are subject to all of the risks and uncertainties, many of which are beyond our control, incident to gathering, transporting, storing, and distributing crude oil and other dark products and buying, gathering, blending and selling crude oil. For a more detailed description of these and other factors that may affect the forward-looking statements, please read "Risk Factors" contained in our universal shelf registration statement on Form S-3 (SEC File No.: 333-107609), filed August 1, 2003, and declared effective by the Securities and Exchange Commission ("SEC") on August 8, 2003, and our annual report on Form 10-K for the year ended December 31, 2003. The risk factors could cause our actual results to differ materially from those contained in any forward-looking statement. You should not put undue reliance on these forward-looking statements. We disclaim any obligation to announce publicly the result of any revision to any of the forward-looking statements to reflect future events or developments.

Introduction

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 condensed consolidated financial statements and the notes thereto set forth elsewhere in this report. The discussion set forth in this section pertains to the unaudited condensed consolidated balance sheet, statements of income and statements of 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 system, (iii) Pacific Terminals LLC ("PT"), owner of the Pacific Terminals storage and distribution system, (iv) Rocky Mountain Pipeline System LLC ("RMP"), owner of the Western Corridor system, the Salt Lake City Core system, and AREPI pipeline, and (v) Ranch Pipeline LLC ("RPL"), the owner of a 22.22% partnership interest in Frontier Pipeline Company ("Frontier"). On January 1, 2004, Anschutz Ranch East Pipeline LLC, which had been a wholly-owned subsidiary of PEG, was merged into RMPS. PPS, PT and PMT comprise our West Coast operations segment. RMPS and RPL comprise our Rocky Mountain operations segment. Certain costs of PEG are also included in each segment.

The financial data included herein reflects the ownership and results of operations of the assets comprising the Pacific Terminals storage and distribution system for the period from July 31, 2003 to March 31, 2004.

This report on Form 10-Q should be read in conjunction with our universal shelf registration statement on Form S-3 (SEC File No.: 333-107609), filed August 1, 2003, and declared effective by the Securities and Exchange Commission ("SEC") on August 8, 2003, and our annual report on Form 10-K for the year ended December 31, 2003.

Overview

We are a publicly traded partnership engaged principally in the business of gathering, transporting, storing and distributing crude oil and other dark products in California and the Rocky Mountain region. We also buy, gather, blend and sell crude oil, activities that are complementary to our pipeline transportation business. We completed our initial public offering of common units on July 22, 2002.

We operate primarily in California, Colorado, Montana, Wyoming and Utah and conduct our business through two regional operating units: West Coast operations and Rocky Mountain operations. We generate revenue principally through pipeline transportation services, storage and distribution services, and buying, gathering, blending and selling activities.

West Coast Operations

Our West Coast operations are located in California and include the only common carrier pipelines that deliver crude oil produced from California's San Joaquin Valley and the two primary California Outer Continental Shelf producing fields, Point Arguello and the Santa Ynez Unit, to refineries and terminal facilities in the Los Angeles Basin and in Bakersfield. In addition, on July 31, 2003, we completed the acquisition of the Pacific Terminals storage and distribution system. These assets service the Los Angeles Basin and strategically position us to benefit from the projected increase in marine imports of crude oil into this region. 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 assets, all of which we operate and own 100%:

Line 2000: Line 2000 is an intrastate common carrier crude oil pipeline that consists of a 130-mile, insulated trunk pipeline with a permitted annual throughput capacity of 130,000 barrels per day ("bpd").

Line 63 System: The Line 63 system is an intrastate common carrier crude oil pipeline system that consists of a 107-mile trunk pipeline with a throughput capacity of approximately 105,000 bpd, 60 miles of distribution pipelines, 156 miles of gathering pipelines, and 22 storage tanks with a total of approximately 1.2 million barrels of storage capacity. Most of these storage assets are located in the San Joaquin Valley and are primarily used to facilitate the transportation of crude oil on our pipelines.

PMT Gathering and Blending System: The PMT gathering and blending system is a proprietary crude oil pipeline system located in the San Joaquin Valley that consists of 103 miles of gathering pipelines and six storage and blending facilities with a total of approximately 0.25 million barrels of storage capacity and up to 65,000 bpd of blending capacity. PMT is interconnected to our Line 63 system. PMT buys, blends and sells crude oil, activities that are complementary to our pipeline transportation business.

Pacific Terminals Storage and Distribution System: The Pacific Terminals storage and distribution system is a storage and pipeline distribution system located in the Los Angeles Basin that consists of 70 miles of distribution pipelines in active service and 34 storage tanks with a total of approximately

9.0 million barrels of storage capacity. Of this total approximately 6.7 million barrels are in active commercial service, 0.4 million barrels are used primarily for "throughput" to other tanks and do not generate revenue independently, approximately 1.7 million barrels are idle but could be reconditioned and brought into service, and approximately 0.2 million barrels are in displacement oil service.

Rocky Mountain Operations

Our Rocky Mountain operations consist of various interests in 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 connection with third-party pipelines. Our Rocky Mountain operations are headquartered in Denver, Colorado, with five field offices in Wyoming. Upon completion of the Rangeland and MAPL acquisitions, these systems will be part of our Rocky Mountain operations and an office will be established in Calgary, Alberta. Please see "Acquisitions" below.

Our Rocky Mountain operations are comprised of the following assets, which form an integrated pipeline network:

Western Corridor System: The Western Corridor system is an interstate and intrastate common carrier crude oil pipeline system that consists of 1,012 miles of pipelines extending from dual origination points at the Canadian border near Cutbank, Montana, where it receives deliveries from Rangeland pipeline, and at Cutbank, Montana, where it receives deliveries from Cenex pipeline, and terminating at Guernsey, Wyoming with connections in Wyoming to Frontier pipeline, Suncor's pipeline, Platte pipeline and to our Salt Lake City Core system. This system consists of three contiguous trunk pipelines: 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. Conoco Pipe Line Company 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 is an interstate and intrastate common carrier crude oil pipeline system that 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. Of the 60,000 bpd delivery capacity into Salt Lake City, approximately 40,000 bpd is delivered directly through our pipelines and approximately 20,000 bpd is delivered indirectly through a connection to a ChevronTexaco pipeline. The Salt Lake City Core system also will be able to receive deliveries this year from Frontier pipeline at Frontier Station, Wyoming. We operate and own 100% of the Salt Lake City Core system.

Frontier Pipeline: Frontier pipeline is an interstate common carrier crude oil pipeline that consists of a 289-mile trunk pipeline with a throughput capacity of approximately 62,200 bpd and three storage tanks with 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 operate Frontier pipeline and own a 22.22% partnership interest in Frontier Pipeline Company, the general partnership that owns Frontier pipeline. Enbridge, Inc. owns the remaining partnership interest in Frontier Pipeline Company.

AREPI Pipeline: AREPI pipeline is an interstate common carrier crude oil pipeline that 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 0.1 million barrels of storage capacity. AREPI pipeline originates at Ranch Station, Utah, where it 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 operate and own 100% of AREPI pipeline.

Key Events in the Three Months Ended March 31, 2004 and Recent Developments

Pending Acquisitions

Pending Rangeland Acquisition. On February 23, 2004, we entered into a definitive purchase and sale agreement to acquire the Rangeland system from BP Canada Energy Company. The Rangeland system is located in the province of Alberta, Canada and consists of Rangeland Pipeline Company, Rangeland Marketing Company and Aurora Pipeline Company Ltd. The acquisition price for the Rangeland system is Cdn$130 million plus an estimated Cdn$26 million for linefill, working capital, transaction costs and transition capital expenditures. At an exchange rate of US$1 to Cdn$1.31, as of March 31, 2004, it is estimated that the total purchase price will be approximately U.S. $119 million. The transaction has received all required governmental approvals and is expected to close in May 2004, following fulfillment of customary closing conditions.

The Rangeland system is a proprietary system that consists of approximately 800 miles of gathering and trunk pipelines. It is a bi-directional system capable of gathering crude oil, condensate and butane and transporting these commodities either north to Edmonton, Alberta via third-party pipeline connections or south to the U.S. border near Cutbank, Montana, where it connects to the Western Corridor system. The trunk pipeline system from Sundre Station to the U.S. border consists of approximately 221 miles of 12-inch pipe, with a 29 mile long 8-inch loop section, and has a current throughput capacity of approximately 85,000 bpd in light crude service. The trunk pipeline system from Sundre Station north to Rimbey Station consists of three parallel pipelines. These parallel trunk lines consist of 56 miles of 12-inch pipe for sweet crude, 63 miles of 8-inch pipes for high sulphur crude, and 56 miles of 8-inch pipes for condensate and butane.

MAPL Letter of Intent. On February 24, 2004, we entered into a non-binding letter of intent to purchase the MAPL system from Imperial Oil Resources. This transaction is subject to completion of a definitive purchase and sale agreement and fulfillment of such closing conditions as may be included in the purchase and sale agreement. This transaction is expected to close in the second quarter of 2004.

The 138-mile, 12-inch and 16-inch diameter MAPL pipeline is a proprietary pipeline system with an estimated throughput capacity of approximately 50,000 bpd in light crude service. The line originates at the Edmonton, Alberta oil hub and extends south to a connection with the Rangeland system at Sundre Station.

Integration and Transition. The Rangeland and MAPL systems have historically been operated as proprietary pipeline systems, without regard to maximizing either pipeline operations or profitability. We intend to make significant changes to the revenue-generating capability of these systems by combining and integrating fully all of our Canadian and U.S. Rocky Mountain pipeline systems under common management, by expanding the throughput capacity of the MAPL system and by establishing a new pump station and receiving terminal in Edmonton, Alberta. This new facility will be able to access multiple sources of Canadian crude oil, which will allow us to participate in the projected increase in production of Canadian synthetic crude oil. Except for one marketing person whom we expect to hire, no members of senior management, nor any financial, marketing or technical personnel who have been associated with the management and support of the Rangeland system have been made available by BP for possible employment with the Partnership following the completion of this acquisition. We have made conditional offers of employment to approximately 40 of BP's field-level employees, who, if they accept our offer, will be hired following BP's formal termination of such employees. We do not intend to hire any executives or employees from Imperial Oil Resources.

Financing. We intend to fund the aggregate purchase price for the Rangeland and MAPL systems with a portion of the net proceeds from our March 2004 issuance of common limited partner units, borrowings under our proposed Cdn$100.0 million revolving credit facility and, if necessary, borrowings under our U.S. revolving credit facility. We have amended the provisions of our U.S. credit agreement relating to investments in "unrestricted subsidiaries" in anticipation of the acquisition of the Rangeland and MAPL systems, which amendment allows us to appropriately fund the capitalization of our Canadian indirect operating subsidiaries.

Project Development

In February 2004, we completed a feasibility study for the development of a new deepwater petroleum import terminal in the Port of Los Angeles ("POLA") to handle marine receipts of crude oil and feedstocks, and we are proceeding with the next phase of development. We also entered into a project development agreement with two subsidiaries of Valero Energy Corporation (the "Valero Agreement") that defined the project facilities that we are to construct, and which is subject to the satisfaction of various conditions, including completion of a mutually satisfactory terminalling services agreement with a 30 year, 50,000 bpd volume commitment from Valero to support the project. In addition, we and the POLA have identified several possible sites for construction of storage facilities by us and have agreed to begin the review process required by the California Environmental Quality Act.

If the Pier 400 Project is successfully developed, the new deepwater berth and related storage facilities will be constructed at Pier 400 and Terminal Island in the POLA, and a new pipeline distribution system will be constructed to connect the terminal facilities to Valero's Wilmington refinery and to other customer facilities through our existing Pacific Terminals storage and distribution system in the Los Angeles Basin. The Pier 400 Project would provide marine receipt facilities with water depth of approximately 81 feet, capable of handling some of the largest tankers, and with the capacity to efficiently accommodate increasing volumes of water borne imported crude oil and refinery feedstocks.

The deepwater berth at Pier 400 would be constructed by the POLA. If the project receives the required permits and approvals, we would construct the oil transfer infrastructure, including a large diameter pipeline system for receiving bulk petroleum liquids from marine vessels, storage tanks with an initial capacity of 1.5 million barrels, and the pipeline distribution system, all at an estimated cost of approximately $130 million, subject to final permitting requirements. Initially, the terminal is expected to handle marine receipts of approximately 100,000 bpd. However, the berth, offloading facilities and pipelines are being designed, subject to permit limitations, to accommodate up to 250,000 bpd. Based on the level of additional customer commitments, the Partnership may construct additional storage tanks. Completion of construction and start up of the project is targeted for late-2006.

In addition to environmental permits, the project will require regulatory approvals from a variety of governmental agencies, including the Board of Harbor Commissioners, the City of Los Angeles and the Los Angeles City Council.

We spent approximately $5.6 million on the project beginning in the second quarter of 2003 through March 31, 2004. Additional capital expenditures of $3 million are expected for 2004. We anticipate funding pre-construction costs through mid-2005 from a portion of the proceeds from the March 2004 issuance of additional common units. Construction of the terminal facility is expected to be financed through a combination of debt and proceeds from the issuance of additional partnership units, including common units.

Expansion

We are also undertaking a $3 million expansion of our pipelines serving Salt Lake City by establishing a new delivery connection from Frontier Pipeline to the Salt Lake City Core system. Existing pipelines into Salt Lake City are currently prorated, or limited by capacity, during the summer season. This connection will increase delivery capacity to Salt Lake City refineries by approximately 9,000 bpd. We are committed to keeping pace with growing demand for crude oil in this region and expect this new connection to be placed in service in July 2004.

Business Fundamentals

Pipeline Transportation

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

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

The availability of crude oil for transportation on our pipelines is dependent in part on the amount of drilling and enhanced recovery activity in the production fields we serve in our West Coast operations and in parts of our Rocky Mountain systems. With the passage of time, production of crude oil in an individual well naturally declines, which can in the short term be offset in whole or in part by additional drilling or the implementation of recovery enhancement measures. In the San Joaquin Valley, California and in the California Outer Continental Shelf ("OCS"), production is generally declining. The expected development of the Rocky Point field in the OCS and, if it occurs, the closure of the Shell Bakersfield refinery, will, we believe, provide an increase in the supply of crude oil available to be transported by us to the Los Angeles Basin, offsetting some or all of the effects of production decline in the short term. In addition, we acquired the Pacific Terminals storage and distribution assets and are developing the Pier 400 project to participate in the marine import business, which is growing as a result of local production decline. In the Rocky Mountains, our pipelines are connected to Canadian sources of crude oil, and we recently announced an agreement and a non-binding letter of intent to acquire two pipeline systems to access significant supplies of Canadian crude oil and synthetic crude oil which we believe will replace any Rocky Mountain production decline and meet growing demand in the Rocky Mountain region. See "Key Events in the Three Months Ended March 31, 2004 and Recent Developments" above.

The tariff rates we charge on Line 2000 and the Line 63 system are regulated by the California Public Utilities Commission (the "CPUC"). Tariffs on Line 2000 are established based on market considerations, subject to certain contractual restraints. Tariffs on Line 63, which are cost-of-service based tariffs, are based upon the costs to operate and maintain the pipeline, as well as charges for the depreciation of the capital investment in the pipeline and the authorized rate of return. The tariff rates charged on our Rocky Mountain pipelines are regulated by either the FERC or the Wyoming Public Service Commission generally under a cost-of-service approach.

Storage and Distribution

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

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

Gathering and Blending

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

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

Acquisitions and New Projects

We intend to continue to pursue acquisitions and new projects for development of additional midstream assets, including pipeline and storage and terminal facilities that are accretive to our cash flow and complement our existing business. We expect to fund acquisitions and new projects with a combination of debt and additional partnership units, including common units. We expect to maintain a debt to total capitalization ratio of approximately 50 percent over time.

Operating Expense

A substantial portion of the operating expenses we incur, including the cost of field and support personnel, maintenance, control systems, telecommunications, rights-of-way and insurance, varies little with changes in throughput. Certain of our costs, however, do vary with throughput, the most material being the cost of power used to run the various pump stations along our pipelines. Major maintenance costs can vary with age and also with regulation requiring inspections at defined intervals. Unanticipated costs can include the costs of cleanup of any oil spills to the extent not covered by insurance.

Employees

The Partnership does not have any employees. All our personnel are employed by our 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. Please read "Note 7 Related Party Transactions" in the footnotes to the condensed consolidated financial statement.

Critical Accounting Policies and Estimates

Our condensed 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 in our annual report on Form 10-K for the year ended December 31, 2003) and estimates, the following may involve a higher degree of judgment and complexity:

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

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

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

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

Our inventory of displacement oil, pipeline linefill and minimum tank volumes is carried in our accounts at the lower of cost and market value. This inventory is held for our long-term use and for the operation of our pipelines and storage facilities and as such is recorded in our property and equipment balance. As oil prices tend to be cyclical, we are exposed to the potential for a write-down to market value. Such a write-down would be a non-cash expense but would not be realized, if at all, until we were to sell such inventory for a price less than our cost.

Results of Operations

Three Months Ended March 31, 2004 Compared to Three Months Ended March 31, 2003

Summary

	Three Months Ended March 31, 2004	2003	Change	Percent
	(In thousands) (unaudited)			
Net income	$ 8,077	$ 6,128	$ 1,949	32%
Net income per limited partner unit				
Basic	$ 0.32	$ 0.29	$ 0.03	10%
Diluted	$ 0.31	$ 0.29	$ 0.02	7%

Net income for the three months ended March 31, 2004 includes the operations of the Pacific Terminals storage and distribution system following the acquisition of these assets on July 31, 2003.

The results of the current quarter reflect the benefit of the Pacific Terminals storage and distribution system and higher volumes and revenue on the Rocky Mountain pipelines, partially offset by lower volumes and revenue from the West coast pipelines, lower margins in the gathering and blending operation, and increased maintenance expenses. There were approximately 20% more limited partner units outstanding in the three months ended March 31, 2004 due to the August 2003 sale of additional common units to partially fund the acquisition of the Pacific Terminals storage and distribution system.

Segment Information

West Coast	Three Months Ended March 31, 2004	2003	Change	Percent
	(In thousands) (unaudited)			
Operating income	$ 12,255	$ 10,723	$ 1,532	14%
Operating data:				
Pipeline throughput (bpd)	133.6	159.3	(25.7)	-16%

The increase in West Coast operating income was primarily due to the acquisition of the Pacific Terminals storage and distribution system. This increase was partially offset by lower margins in the gathering and blending operations and a reduction in pipeline transportation revenue as average daily pipeline throughput decreased to 133,600 barrels per day for the three months ended March 31, 2004, compared to 159,300 barrels per day for the corresponding period of the prior year. Throughput volumes during the first quarter of this year were adversely affected by refinery maintenance activities in the Los Angeles Basin this year. This was coupled with San Francisco area refinery maintenance during the first quarter of last year which resulted in higher volumes being delivered from the San Joaquin Valley to Los Angeles refineries in the three months ended March 31, 2003. The natural decline of California Outer Continental Shelf ("OCS") and San Joaquin Valley production also continued to reduce available crude supplies.

Rocky Mountains	Three Months Ended March 31, 2004	2003	Change	Percent
	(In thousands) (unaudited)			
Operating income	$ 3,641	$ 3,342	$ 299	9%
Operating data (bpd):				
Salt Lake City Core system	62.0	64.8	(2.8)	-4%
Western Corridor system	16.0	13.4	2.6	19%
AREPI pipeline	43.9	35.5	8.4	24%
Frontier pipeline	43.9	35.3	8.6	24%

Operating income increased due to higher volumes on the Western Corridor and increased demand by refineries in the Salt Lake City area this year, increasing Frontier and AREPI pipeline volumes, compared to 2003 when demand was lower due to refinery turnarounds. Additionally, residual transition costs in the first quarter of 2003 from our acquisition of the Western Corridor and Salt Lake City Core systems in 2002 impacted the results in 2003. The elimination of transition costs in 2004, however, was offset by increased pipeline maintenance expenses and power costs due to higher natural gas prices in 2004.

Statement of Income Discussion and Analysis

	Three Months Ended March 31, 2004	2003	Change	Percent
	(In thousands) (unaudited)			
Pipeline transportation revenue	$ 24,727	$ 25,320	$ (593)	-2%

Lower West Coast pipeline revenues due to refinery maintenance activities in California, coupled with natural production decline of California OCS and San Joaquin Valley crude oil production, were partially offset by higher Rocky Mountain pipeline revenues due to higher volumes on the Western Corridor system and increased demand by Salt Lake City area refineries.

	Three Months Ended March 31, 2004	2003	Change	Percent
	(In thousands) (unaudited)			
Storage and distribution revenue	$ 10,123	$	$ 10,123	

The acquisition of the Pacific Terminals storage and distribution system on July 31, 2003 resulted in storage and distribution revenue of $10.1 million for the three months ended March 31, 2004.

	Three Months Ended March 31, 2004	2003	Change	Percent
	(In thousands) (unaudited)			
Crude oil sales	$ 85,927	$ 92,282	$ (6,355)	-7%
Crude oil purchases	(81,115)	(86,652)	(5,537)	-6%
Crude oil sales, net of purchases	$ 4,812	$ 5,630	$ (818)	-15%

The decrease in net crude oil sales and purchases for 2004 was primarily the result of lower volumes as demand for blended crude oil has diminished with changed refined products specifications

29

in 2004. Higher margin blending activities are being replaced with lower margin gathering business. We consider this activity to be complementary to our pipeline transportation operations.

	Three Months Ended March 31,			
	2004	2003	Change	Percent
		(In thousands) (unaudited)		
Operating expenses	$ 18,917	$ 12,648	$ 6,269	50%

The increase in operating expense was related primarily to the acquisition of the Pacific Terminals storage and distribution assets. We also experienced higher maintenance and power costs in the Rocky Mountains as a result of the timing of internal pipeline inspection work and increased natural gas prices, respectively.

	Three Months Ended March 31,			
	2004	2003	Change	Percent
		(In thousands) (unaudited)		
Transition costs	$	$ 397	$ (397)	-100%

Transition costs in 2003 consisted of employee transition bonus payments related to our purchase of the Western Corridor and Salt Lake City Core systems in 2002.

	Three Months Ended March 31,			
	2004	2003	Change	Percent
		(In thousands) (unaudited)		
General and administrative expense	$ 3,854	$ 3,982	$ (128)	-3%

The decrease in general and administrative expense was mainly attributable to lower long term incentive plan costs in the three months ended March 31, 2004 and higher legal fees incurred during the three months ended March 31, 2003 in connection with rate case litigation in the Rocky Mountains.

	Three Months Ended March 31,			
	2004	2003	Change	Percent
		(In thousands) (unaudited)		
Depreciation and amortization	$ 5,242	$ 4,181	$ 1,061	25%

The increase in depreciation and amortization includes $0.9 million for depreciation on the Pacific Terminals storage and distribution system.

Three Months Ended March 31,			
2004	2003	Change	Percent
	(In thousands) (unaudited)		

	Three Months Ended March 31,			
Share of net income of Frontier	$ 393	$ 341	$ 52	15%

30

Our increased share of Frontier net income was attributable to increased volumes on Frontier pipeline.

	Three Months Ended March 31,			
	2004	2003	Change	Percent
	(In thousands) (unaudited)			
Interest expense	$ 4,126	$ 4,046	$ 80	2%

Interest expense increased due to an increase in borrowings incurred to partially fund the acquisition of Pacific Terminals storage and distribution system. Our weighted average borrowings during 2004 were $304 million compared to $225 million in 2003. However, the increase in borrowings was offset by a lower weighted average interest rate of 5.5% during 2004 compared to a weighted average interest rate of 6.6% in 2003. The decrease in the average interest rate was due in part to renegotiation of interest rates in December 2003 under our credit facilities, and also to lower market interest rates.

Liquidity and Capital Resources

We believe that cash generated from operations, together with our cash balance and our unutilized borrowing capacity, will be sufficient to meet our planned distributions, our working capital requirements, anticipated sustaining capital expenditures and scheduled debt payments in the next three years.

We intend to finance the recently announced Canadian acquisitions through a combination of borrowings under a new $100 million (Canadian) revolving credit facility (equivalent to approximately U.S. $76 million based on an exchange rate on March 31, 2004 of $1 US to $1.31 Canadian) that is currently being negotiated and with a portion of the net proceeds from the March 2004 issuance of additional Partnership common units.

The financing plan for the construction of our proposed Pier 400 Project is under development, but will likely include both proceeds from debt and the issuance of additional units. The final structure will depend on market conditions.

On August 1, 2003, the Partnership, PEG and certain subsidiaries of PEG filed a universal shelf registration statement on Form S-3 with the SEC to register the issuance and sale, from time to time and in such amounts as determined by the market conditions and needs of the Partnership, of up to $550.0 million of common units of the Partnership and debt securities of both the Partnership and PEG. The SEC declared the registration statement effective on August 8, 2003. At April 28, 2004, we have approximately $280 million of remaining availability under this registration statement.

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

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

Operating, Investing and Financing Activities

	Three Months Ended March 31,		
	2004	2003	Change
		(In thousands) (unaudited)	
Net cash provided by operating activities	$ 13,338	$ 5,894	$ 7,444
Net cash used in investing activities	(12,333)	(513)	(11,820)
Net cash provided by (used in) financing activities	31,128	(9,878)	41,006

Net cash provided by operating activities

The increase in the net cash from operating activities of $7.4 million, or 126%, was the result of higher operating income, together with a decrease in cash used for working capital.

Net cash used in investing activities

The amount in 2004 relates primarily to our acquisition and development activities. The 2004 period includes $9.9 million related to a deposit paid and acquisition costs incurred for the Rangeland Pipeline system and MAPL assets. Capital expenditures were $2.4 million in 2004, of which $0.5 million related to sustaining capital projects, $0.1 million related to the transition of the Pacific Terminals storage and distribution system, and $1.8 million related to expansion. In 2003, capital expenditures were $0.6 million, of which $0.3 million related to sustaining capital projects, $0.1 million related to transition projects, and $0.2 million related to expansion. Additionally, we continue to develop the Pier 400 Project. Consequently, we capitalized $0.3 million during the period ended March 31, 2004.

Net cash provided by and used in financing activities

The amount in 2004 of $31.1 million includes net repayment of $73 million under our revolving credit facility, $12.4 million in distributions to the limited and general partner interests, and net proceeds of $116.7 million from an equity offering completed on March 30, 2004, which will be used to in part to fund a portion of the pending acquisition of the Rangeland Pipeline System and proposed MAPL acquisition. The cash used in financing activities in 2003 consisted only of distributions to the limited and general partner interests.

Credit Facilities

As of March 31, 2004 and December 31, 2003, we had long-term debt obligations of $225.0 million and $298.0 million, respectively.

PEG is the borrower under both the revolving credit facility and the term loan, which are guaranteed by the Partnership and certain of PEG's operating subsidiaries. The revolving credit facility and the term loan are both fully recourse to PEG and the guarantors, but non-recourse to our 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.

The revolving credit facility is a $200.0 million facility that is available for general partnership purposes, including working capital, letters of credit, distributions to unitholders and to finance future acquisitions. The revolving credit facility also has a borrowing sublimit of $45.0 million for working capital, letters of credit and partnership distributions to unitholders. Borrowings under the revolving credit facility are limited by various financial covenants that are set forth in the credit agreement. As of March 31, 2004, we were in compliance with all covenants under the credit agreement. At March 31, 2004, there were no borrowings under the revolving credit facility and no letters of credit were outstanding as of that date.

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

We may prepay all loans under the revolving credit facility and the term loan. Except as otherwise subsequently agreed by certain of the lenders, mandatory prepayments and commitment reductions will generally be required to reflect the net cash proceeds of assets sold other than in the ordinary course of business and the net proceeds of new senior secured debt offerings, subject to certain exceptions.

Effective December 12, 2003, PEG amended its credit agreement to reduce the interest rates and other fees. Subject to certain limited exceptions, indebtedness under the revolving credit facility and the term loan now bear interest at PEG'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 0.25% for the term loan) or (ii) LIBOR plus an applicable margin ranging from 0.75% to 2.00% for the revolving credit facility and ranging from 2.00% to 2.25% 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.

PEG incurs a commitment fee which ranges from 0.125% to 0.375% per annum on the unused portion of the revolving credit facility. Under the credit agreement, as amended, 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. The credit agreement also contains covenants requiring PEG, including certain of its subsidiaries, to maintain specified financial ratios. In addition, the credit agreement contains other restrictive covenants. As of March 31, 2004, we were in compliance with all covenants under the credit agreement.

As of March 31, 2004, we had available but undrawn credit of $91 million under the revolving credit facility, together with an additional $74 million available for acquisitions for up to 270 days. These amounts could be increased based on an acquired business's earnings before interest, taxes, depreciation and amortization ("EBITDA") with the acceptance of the administrative agent for our credit facilities.

In August and September 2002, PEG entered into interest rate swap agreements pursuant to which it hedged its exposure to variability in future cash flows attributable to the LIBOR interest payments due on $170.0 million outstanding under the term loan. 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 debt of approximately 6.50%. These interest rate swap agreements are described further in "Item 3 Quantitative and Qualitative Disclosures About Market Risk" below.

Capital Requirements

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

- sustaining capital expenditures to replace partially or fully depreciated assets in order to maintain the existing operating capacity or efficiency of our assets and extend their useful lives;
- transitional capital expenditures to integrate acquired assets into our existing operations; and
- expansion capital expenditures to expand or increase the efficiency of the existing operating capacity of our assets, whether through construction or acquisition, such as placing new storage

tanks in service to increase our storage capabilities and revenue, and adding new pump stations or pipeline connections to increase our transportation throughput and revenue.

We have forecasted total capital expenditures for our existing operations of $14 million in 2004, including $3 million for the Pier 400 Project, $7 million for other expansion projects, $1 million for transition capital projects and $3 million for sustaining capital projects.

Off-Balance Sheet Arrangements

The Partnership has no off-balance sheet arrangements.

Accounting Pronouncements

See discussion of newly issued accounting pronouncements in "Note 1 Summary of Significant Accounting Policies" in the accompanying condensed consolidated financial statements.

ITEM 3. 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.

PEG has interest rate swap agreements with aggregate notional principal amounts of $30 million maturing in 2007 and $140 million maturing in 2009. 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 PEG's 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 debt of approximately 6.50% (including the current applicable margin of 2.25%).

As of March 31, 2004, interest rates, as measured by current 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 $9.3 million on the aggregate interest rate hedge, which is recorded as a liability at March 31, 2004. The $9.3 million liability is shown on the condensed consolidated balance sheet in two components, a current liability of $5.0 million, and a long term liability of $4.3 million. The unrealized loss reflecting the decline in interest rates from the inception of the swaps, is shown in "accumulated other comprehensive income," a component of partners' capital, and not in the condensed consolidated income statement. Should interest rates remain unchanged from the March 31, 2004 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 approximately 6.50%.

We are subject to risks resulting from interest rate fluctuations as the interest cost on the remaining $55.0 million outstanding under our term loan is based on variable rates. If the LIBOR rate were to increase 1.0% in 2004 as compared to the rate at March 31, 2004, our interest expense for the remainder of 2004 would increase $0.4 million based on the outstanding debt at March 31, 2004, which has not been hedged.

We use, on a limited basis, certain derivative instruments (principally futures and options) to hedge our minimal exposure to market price volatility related to our inventory or future sales of crude oil. We do not enter into speculative derivative activities of any kind. Derivative instruments are included in other assets in the accompanying condensed consolidated balance sheets. Although we generally do not own the crude oil that we transport in our pipelines, in our PMT operations we purchase crude oil for subsequent blending, transportation and resale primarily in the Los Angeles Basin. Changes in the fair value of our derivative instruments related to crude oil inventory are recognized in net income. For the three months ended March 31, 2004 and 2003, "crude oil sales, net of purchases" were net of $0.2 million in each year, reflecting changes in the fair value of PMT's derivative instruments for its marketing activities. In addition, changes in the fair value of our derivative instruments related to the future sale of crude oil are deferred and reflected in "accumulated other comprehensive income," a component of partners' capital, until the related revenue is reflected in the consolidated statements of income. As of March 31, 2004, $0.5 million relating to the changes in the fair value of derivative instruments was included in "accumulated other comprehensive income."

ITEM 4. Controls and Procedures

Disclosure Controls and Procedures

As of the end of the quarterly period ended March 31, 2004, Irvin Toole, Jr., Chief Executive Officer of our General Partner, and Gerald A. Tywoniuk, Chief Financial Officer of our General Partner, evaluated the effectiveness of our disclosure controls and procedures. Based on these evaluation, they believe that:

- our disclosure controls and procedures were effective in ensuring that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 was 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 in ensuring that material information required to be disclosed by us in the report we file or submit under the Securities Exchange Act of 1934 was accumulated and communicated to our management, including the Chief Executive Officer and the Chief Financial Officer of our General Partner, as appropriate to allow timely decisions regarding required disclosure.

Internal Control Over Financial Reporting

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

PART II. OTHER INFORMATION

ITEM 1. Legal Proceedings

See discussion of legal proceedings in "Note 9 Commitments and Contingencies" in the accompanying condensed consolidated financial statements.

ITEM 6. Exhibits and Reports on Form 8-K

(a)
Exhibits

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

Exhibit Number	Description
* Exhibit 3.1	Amendment No. 3 to First Amended and Restated Agreement of Limited Partnership of Pacific Energy Partners, L.P.
* Exhibit 31.1	Certification of Principal Executive Officer of Pacific Energy GP, Inc., General Partner of Pacific Energy Partners, L.P., as required by Rule 13a-14(a) of the Securities Exchange Act of 1934
* Exhibit 31.2	Certification of Principal Financial Officer of Pacific Energy GP, Inc., General Partner of Pacific Energy Partners, L.P., as required by Rule 13a-14(a) of the Securities Exchange Act of 1934
Exhibit 32.1	Certification of Chief Executive Officer of Pacific Energy GP, Inc., General Partner of Pacific Energy Partners, L.P., pursuant to 18 U.S.C. §1350
Exhibit 32.2	Certification of Chief Financial Officer of Pacific Energy GP, Inc., General Partner of Pacific Energy Partners, L.P., pursuant to 18 U.S.C. §1350

*
Filed herewith.

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

(b)
Reports on Form 8-K

The Partnership filed the following reports on Forms 8-K and 8-K/A during the three months ended March 31, 2004:

Date of Event Reported	Item(s) Reported	Description
January 27, 2004	Items 7, 9 & 12*	Filed in connection with the Partnership's fourth quarter 2003 earnings release on January 27, 2004.
March 2, 2004	Items 7 & 9*	Filed in connection with the Partnership's press release on February 24, 2004 announcing its agreements to purchase Canadian pipelines.
March 15, 2004	Items 7, 9 & 12*	Filed in connection with the Partnership's press release, dated March 10, 2004, announcing Adjustment to 2003 Net Income.
March 24, 2004	Items 5 & 7	Filed in connection with the filing of the consolidated balance sheet of Pacific Energy GP, Inc. as of December 31, 2003.

*
The information in the Forms 8-K and 8-K/A furnished pursuant to Item 9 is not considered to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934 or otherwise subject to the liabilities of that section.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Partnership has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PACIFIC ENERGY PARTNERS, L.P.
By: PACIFIC ENERGY GP, INC.
its General Partner

May 4, 2004	By:	/s/ IRVIN TOOLE, JR.
		Irvin Toole, Jr. *President and Chief Executive Officer* *(Principal Executive Officer)*
May 4, 2004	By:	/s/ GERALD A. TYWONIUK
		Gerald A. Tywoniuk *Senior Vice President, Chief Financial Officer and Treasurer* *(Principal Financial Officer)*

EXHIBIT INDEX

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Filed herewith.

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