PACIFIC ENERGY PARTNERS LP
Form 10-Q
August 09, 2004

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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 June 30, 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 (State or other jurisdiction of incorporation or organization)	**68-0490580** (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 19,069,948 of the registrant's Common Units and 10,465,000 of the registrant's Subordinated Units outstanding at June 30, 2004.

PACIFIC ENERGY PARTNERS, L.P.

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PART I. FINANCIAL INFORMATION

ITEM 1. Financial Statements

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

CONDENSED CONSOLIDATED BALANCE SHEETS

	June 30, 2004	December 31, 2003
	(in thousands) (unaudited)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 21,861	$ 9,699
Crude oil sales receivable	29,496	33,766
Transportation and storage accounts receivable	27,970	16,828
Crude oil inventory	10,588	2,272
Spare parts inventory	1,637	1,644
Prepaid expenses	3,249	4,182
Other	1,196	405
Total current assets	95,997	68,796
Property and equipment, net	705,048	567,954
Investment in Frontier (note 4)	6,817	6,886
Other assets	43,650	6,567
	$ 851,512	$ 650,203
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 15,973	$ 11,506
Accrued crude oil purchases	29,331	31,602
Due to related parties (note 8)	1,187	580
Derivatives liability current portion	704	4,986
Other	3,043	1,317
Total current liabilities	50,238	49,991
Senior notes and credit facilities, net of unamortized discount of $4,354 at June 30, 2004 (note 5)	335,735	298,000
Deferred income taxes	34,928	
Derivatives liability		622
Other liabilities	8,172	6,523
Total liabilities and deferred income taxes	429,073	355,136
Commitments and contingencies (note 10)		
Partners' capital (note 7):		

	June 30, 2004	December 31, 2003
Common unitholders (19,069,948 and 14,441,763 units outstanding at June 30, 2004 and December 31, 2003, respectively)	366,938	246,952
Subordinated unitholders (10,465,000 units outstanding at June 30, 2004 and December 31, 2003)	45,304	49,010
General Partner interest	6,469	3,975
Undistributed employee long-term incentive compensation	2,003	738
Accumulated other comprehensive income (loss)	1,725	(5,608)
Net partners' capital	422,439	295,067
	$ 851,512	$ 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 June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(in thousands, except per unit amounts) (unaudited)			
Pipeline transportation revenue	$ 26,992	$ 25,758	$ 51,719	$ 51,078
Storage and distribution revenue	9,259		19,382	
Pipeline buy/sell transportation revenue	3,690		3,690	
Crude oil sales, net of purchases of $94,382 and $88,408 for the three months ended June 30, 2004 and 2003 and $175,497 and $174,700 for the six months ended June 30, 2004 and 2003	6,056	4,979	10,868	10,609
Net revenue before operating expenses	45,997	30,737	85,659	61,687
Expenses:				
Operating	20,683	14,344	39,600	26,992
Transition costs	184		184	397
General and administrative	3,636	3,002	7,490	6,984
Depreciation and amortization	5,713	4,205	10,955	8,386
	30,216	21,551	58,229	42,759
Share of net income of Frontier	391	386	784	727
Operating income	16,172	9,572	28,214	19,655
Interest expense	(4,383)	(4,102)	(8,509)	(8,148)
Write-off of deferred financing cost and interest rate swap termination expense (note 6)	(2,901)		(2,901)	
Other income	226	156	387	247
Income before income taxes	9,114	5,626	17,191	11,754
Income tax benefit (expense):				
Current	(32)		(32)	
Deferred	46		46	
	14		14	
Net income	$ 9,128	$ 5,626	$ 17,205	$ 11,754
Net income for the general partner interest	$ 183	$ 112	$ 344	$ 235
Net income for the limited partner interests	$ 8,945	$ 5,514	$ 16,861	$ 11,519
Basic and diluted net income per limited partner unit	$ 0.30	$ 0.26	$ 0.62	$ 0.55
Weighted average limited partner units outstanding:				
Basic	29,479	20,930	27,239	20,930
Diluted	29,632	21,086	27,402	21,065

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 Income (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			10,365	6,496	344			17,205
Distribution to partners			(16,337)	(10,202)	(542)			(27,081)
Issuance of common units, net of fees and offering expenses (note 7)	4,625		125,881					125,881
General partner contribution related to issuance of common units (note 7)					2,690			2,690
Undistributed employee compensation under long-term incentive plan						1,351		1,351
Issuance of common units pursuant to long-term incentive plan	3		77		2	(86)		(7)
Foreign currency translation adjustment							2,429	2,429
Change in fair value of hedging derivatives							4,904	4,904
Balance, June 30, 2004	19,070	10,465	$ 366,938	$ 45,304	$ 6,469	$ 2,003	$ 1,725	$ 422,439

See accompanying notes to condensed consolidated financial statements.

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

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(in thousands) (unaudited)			
Net income	$ 9,128	$ 5,626	$ 17,205	$ 11,754
Change in fair value of hedging derivatives	9,140	(4,127)	4,904	(4,988)
Foreign currency translation adjustment	2,429		2,429	
Comprehensive income	$ 20,697	$ 1,499	$ 24,538	$ 6,766

See accompanying notes to condensed consolidated financial statements.

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

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(in thousands) (unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 17,205	$ 11,754
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	10,955	8,386
Amortization of debt issue costs and accretion of bond discount	670	557
Write-off of deferred financing cost	2,321	
Non-cash portion of employee compensation under long-term incentive plan	1,351	1,843
Deferred tax expense (benefit)	(46)	
Share of net income of Frontier	(784)	(727)
Distributions from Frontier, net	668	1,333
	32,340	23,146
Net changes in operating assets and liabilities:		
Crude oil sales receivable	4,270	(9,894)
Transportation and storage accounts receivable	(8,757)	(933)
Other current assets and liabilities	267	2,894
Accounts payable and other accrued liabilities	4,284	(3,178)
Accrued crude oil purchases	(2,271)	7,450
Other non-current assets and liabilities	(261)	(311)
	(2,468)	(3,972)
NET CASH PROVIDED BY OPERATING ACTIVITIES	29,872	19,174
CASH FLOWS FROM INVESTING ACTIVITIES		
Acquisitions	(139,050)	
Additions to property and equipment	(7,896)	(1,191)
Other		47
NET CASH USED IN INVESTING ACTIVITIES	(146,946)	(1,144)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of common units, net of fees and offering expenses	125,881	
Capital contributions from the general partner	2,690	
Net proceeds from senior notes offering	241,086	
Repayment of term loan	(225,000)	
Proceeds from bank credit facilities	154,168	
Repayment of bank credit facilities	(141,500)	
Deferred bank financing costs	(1,008)	
Distributions to partners	(27,081)	(19,755)

	Six Months Ended June 30,	
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	129,236	(19,755)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	12,162	(1,725)
CASH AND CASH EQUIVALENTS, beginning of reporting period	9,699	23,873
CASH AND CASH EQUIVALENTS, end of reporting period	$ 21,861	$ 22,148
Supplemental disclosures:		
Cash paid for interest	$ 8,896	$ 7,536
Non-cash financing and investing activities:		
Change in fair value of hedging derivatives	$ 4,904	$ (4,988)
Foreign currency translation adjustment	$ 2,429	$

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

June 30, 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 related products in California and the Rocky Mountain region of the U.S. and Canada. The Partnership generates revenue primarily by transporting crude oil on its pipelines and by leasing storage capacity. The Partnership also buys, blends and sells crude oil, activities that are complementary to the Partnership's pipeline transportation business. The Partnership operates primarily in California, Colorado, Montana, Wyoming and Utah in the United States and in Alberta, Canada and conducts its business through two regional operating units: West Coast operations and Rocky Mountain operations.

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

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

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

PPS, PT and PMT comprise the West Coast segment. RMPS, RPL, PEG Canada, RPC, APC, RPP, RNPC and RMC 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 owns 10,465,000 subordinated units of the Partnership.

On July 31, 2003, PT completed the acquisition of certain 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 since the date of acquisition.

On May 11, 2004, subsidiaries of PEG Canada completed the acquisition of all of the outstanding capital stock of RPC, RMC and APC, which owned various components of the Rangeland Pipeline system, for an aggregate cash purchase cost of approximately $116 million. The purchase was funded through a combination of proceeds from the Partnership's March 30, 2004 equity offering and the Partnership's Canadian credit facility. The consolidated financial statements reflect the ownership and results of operations of Rangeland Pipeline system since the date of acquisition.

On June 30, 2004, a subsidiary of PEG Canada completed the acquisition of the Mid-Alberta Pipeline ("MAPL") pipeline for an aggregate purchase price of approximately $30 million, including capital expenditures of approximately US$3 million to be incurred in the first year for a new initiating pump station, tanks and pipeline connections. The purchase was funded principally from the Partnership's Canadian credit facility. The consolidated financial statements reflect the ownership and results of operations of MAPL pipeline since 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 and six months ended June 30, 2004 and 2003 are not necessarily indicative of the results of operations for the full year. The financial data for the three and six months ended June 30, 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.

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.

Revenue Recognition

Revenue from the Rangeland Pipeline system and the MAPL pipeline is recognized upon delivery of the crude oil, condensate and butane to the customer. Customers who wish to transport product on the Rangeland pipelines may either: (i) sell product to RMC at the inlet to the pipeline without repurchasing product from RMC; or (ii) sell product to RMC at an inlet point and repurchase such product at agreed upon delivery points for the price paid at the inlet to the pipeline plus an established location differential on a pre-arranged basis.

Derivative Instruments

The Partnership uses, on a limited basis, certain derivative instruments (principally futures and options) to hedge its minimal exposure to market price volatility related to its crude oil inventory or future sales of crude oil. Derivatives used to hedge market price volatility related to inventory are generally designated as fair value hedges, and derivatives related to future sale of crude oil are generally designated as cash flow hedges. The Partnership does not engage in speculative derivative activities. Derivative instruments are included in other assets in the accompanying consolidated balance sheets. Changes in the fair value of the Partnership's derivative instruments related to crude oil inventory are recognized in net income. "Crude oil sales, net of purchases" were net of $0.3 and $0.1 million for the three months ended June 30, 2004 and 2003, and $0.5 and $0.3 for the six months ended June 30, 2004 and 2003, respectively, reflecting changes in the fair value of PMT's derivative instruments held for its crude oil marketing activities. Changes in the fair value of the Partnership's 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 included in the consolidated statements of income. As of June 30, 2004, $0.7 million relating to the changes in the fair value of highly effective derivative instruments was included in "accumulated other comprehensive income" and is expected to be reclassified to earnings in 2004.

In August and September 2002, PEG entered into three interest rate swap agreements that were to mature in 2009, with notional amounts of $140.0 million, and two interest rate swap transactions that were to mature in 2007, with notional amounts of $30.0 million. The Partnership designated these swaps as a hedge of its exposure to variability in future cash flows attributable to the LIBOR interest payments due on $170.0 million outstanding under PEG's term loan facility. The average swap rate on this $170.0 million of debt was approximately 4.25%, resulting in an all-in interest rate on the $170.0 million of debt of approximately 6.50% (including the applicable margin of 2.25%). In June 2004, in conjunction with the issuance of the 7.125% Senior Notes and the repayment of the term loan, PEG bought back the swaps for a loss of $0.6 million.

In connection with the issuance of the 7.125% Senior Notes, the Partnership entered into interest rate swap agreements with an aggregate notional principal amount of $80.0 million to receive interest at a fixed rate of 7.125% and to pay interest at an average variable rate of six month LIBOR plus 1.6681% (set in advance or in arrears depending on the swap transaction). The interest rate swaps matures June 15, 2014 and are generally callable at the same dates and terms as the 7.125% Notes. The Partnership designated these swaps as a hedge of the change in the Senior Notes fair value attributable to changes in the six month LIBOR interest rate. Changes in fair values of the interest rate swaps are recorded into earnings each period. Similarly, changes in the fair value of the underlying $80.0 million of Senior Notes are recorded into earnings each period. The offsetting difference of recording the change in fair value of the interest rate swaps and the change in fair value of $80.0 million Senior Notes into earnings is not expected to have a material impact on earnings as movement in fair value of the interest rate swap and the underlying debt are expected to be highly correlated.

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

Credit risk is the risk of loss arising from the failure of the derivative agreement counterparty to perform under the terms of the derivative agreement. When the fair value of a derivative agreement is positive, the counterparty is liable to the Partnership, which creates credit risk for the Partnership. When the fair value of a derivative agreement is negative, the Partnership is liable to the counterparty and, therefore, it creates credit risk for the counterparty. As of June 30, 2004, the counterparties to the Partnership's crude oil hedging activities did not represent a credit risk to the Partnership as the fair value of each derivative agreement was negative.

Foreign Currency Translation

The financial statements of operating subsidiaries in Canada are measured using the Canadian dollar as the functional currency. Balance sheet amounts are translated at the end of period exchange rate and income statement and cash flow amounts are translated at the average exchange rate for the period. Adjustments from translating these financial statements into U.S. dollars are accumulated in the equity section of the balance sheet under the caption, "accumulated other comprehensive income (loss)."

Income Taxes

The Partnership and its U.S. subsidiaries are not taxable entities and are not subject to federal or state income taxes as the tax effect of operations is accrued to its unitholders. The Partnership's Canadian subsidiaries are taxable entities in Canada and are subject to Canadian federal and provincial income taxes. In addition, monies repatriated from Canada into the U.S. may be subject to withholding taxes.

Net income for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under the Partnership's First Amended and Restated Agreement of Limited Partnership, as amended. Individual unitholders have different investment bases depending upon the timing and price of acquisition of partnership units. Further, each unitholder's tax accounting, which is partially dependent upon the unitholder's tax position, differs from the accounting followed in the 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. Individual unitholders will generally have no responsibility to file Canadian tax returns.

Income taxes are accounted for under the asset and liability method. Under this method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in operations in the period that includes the enactment date.

Pursuant to FAS No. 109, "Accounting for Income Taxes", in the second quarter of 2004, the Partnership recorded a deferred tax liability of $33.9 million, representing the tax effect of the difference between the amounts paid for shares of RPC, RMC and APC, and the underlying tax basis of the assets.

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 June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(in thousands) (unaudited)			
Basic weighted average limited partner units	29,479	20,930	27,239	20,930
Effect of restricted units	140	147	148	129
Effect of options	13	9	15	6
Diluted weighted average limited partner units	29,632	21,086	27,402	21,065

Reclassifications

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

Rangeland

On May 11, 2004, the Partnership completed the acquisition of all of the outstanding shares of Rangeland Pipeline Company ("RPC"), Rangeland Marketing Company ("RMC") and Aurora Pipeline Company Ltd. ("APC"), the corporations that owned various components of the Rangeland Pipeline System from BP Canada Energy Company ("BP"). The Rangeland Pipeline System is located in the province of Alberta, Canada. The acquisition price for shares of RPC, RMC and APC was Cdn$130 million plus approximately Cdn$29 million for linefill, working capital, transaction costs and transition capital expenditures. The aggregate purchase cost was approximately U.S. $116 million and was funded through a combination of proceeds from our March 30, 2004 equity offering and a Cdn$45 million borrowing from a new Cdn$100 million revolving credit facility in Canada. The acquisition was accounted for as an acquisition of assets.

The majority of the Rangeland Pipeline System was constructed in 1966 with smaller portions being built as early as 1955 and certain pump stations built as late as 1971. The Partnership anticipates depreciating the pipeline over forty years from the purchase date.

Pursuant to a transportation service agreement between RMC, RPC and APC, RMC has contracted for the rights to the entire capacity of the Rangeland pipeline. Customers who wish to transport product on the Rangeland pipelines may, therefore, either: (i) sell product to RMC at the inlet to the pipeline without repurchasing product from RMC; or (ii) sell product to RMC at an inlet point and repurchase such product at agreed upon delivery points for the price paid at the inlet to the pipeline plus an established location differential. RMC owns the buy/sell contracts with customers, which were assumed with the purchase, but the marketing function was conducted by employees of BP to whom we were not able to and did not offer employment.

The Rangeland Pipeline System has historically been operated without regard to maximizing either pipeline throughput or profitability; rather, it was operated as an integral part of a larger marketing and trading oriented enterprise. Similarly the MAPL Pipeline, which the Partnership also purchased (see below), was not operated with regard to maximizing pipeline operations or profitability; it was operated as a cost center in a larger enterprise. The Partnership intends to make significant changes to the revenue-generating capability of both systems by combining and integrating fully all of its Canadian and U.S. Rocky Mountain pipeline systems under common management, by expanding the throughput capacity of the MAPL system and by connecting into other pipelines and establishing a new pump station and receiving terminal in Edmonton, Alberta. This new facility will be able to access additional sources of Canadian crude oil, which will allow the Partnership to participate in the projected increase in production of Canadian synthetic crude oil.

In effect, the Partnership is converting what has been primarily a gathering system for crude oil, condensate and butane in southern Alberta into a main line transportation system that will be able to transport multiple grades of conventional and synthetic crude oils from the Edmonton oil hub to U.S. Rocky Mountain refining centers.

Until April 2003, the assets comprising the Rangeland Pipeline System were held by three legal entities: BP, APC and BP Canada Energy Resources Company ("BPR"). In April 2003, in order to facilitate their sale, BPR formed RPC and RMC, and transferred their Rangeland pipeline and marketing related assets to the newly formed entities. APC, which contains only a short segment of pipeline and *de minimis* other assets, liabilities, revenues and expenses, remained unchanged. None of RPC, RMC or APC ever had any employees of their own. All operations and administrative and technical support functions associated with the Rangeland pipeline system, including field services and operations, executive management, marketing, engineering, environmental, risk management, payroll, treasury, human resources and legal remained with BPR and BP. These included services provided by approximately ninety BP employees who also provided varying amounts of support for BP's other pipelines.

Although the RPC and RMC legal entities were formed in April 2003, revenues, expenses, and other financial measures continued to be included within the financial statements of BPR and BP. Financial statements for RPC, RMC and Aurora were not maintained on a current basis.

Upon closing of the purchase transaction, BP terminated employees directly involved in the operation of the Rangeland pipeline, including field-level supervisors, and the Partnership hired those who accepted an offer of employment. Except for one former marketing person (who had not been directly involved with marketing of the Rangeland Pipeline System for several years), no members of senior management, and no financial, marketing or technical personnel who had been associated with the management and support of the Rangeland system were made available by BP for possible employment with the Partnership following the completion of this acquisition. Consequently, the Partnership hired its own marketing, accounting and technical staff, which are located in its new

Calgary office or in Olds, Alberta. The Partnership also utilizes its existing executive and support staff in Long Beach, California and Denver, Colorado to provide management oversight and administrative and technical support for the Alberta assets.

The Partnership also did not acquire accounting software or computer hardware with the purchase. The Partnership was able, however, to acquire as part of the transaction, the Supervisory Control and Data Acquisition (SCADA) system necessary to operate the pipeline. Subsequent to the closing, the Partnership acquired software associated with the complex task of volumetric and revenue accounting from the seller for no additional consideration. The Partnership will use its existing financial accounting software for other accounting functions.

Mid Alberta Pipeline

On June 30, 2004, the Partnership completed the acquisition of the MAPL Pipeline from Imperial Oil. The MAPL pipeline is located in Alberta, Canada. The acquisition price for MAPL was Cdn$31.5 million, of which Cdn$5.0 million will be payable in three years. In addition to MAPL pipeline, the Partnership acquired linefill for Cdn$5.0 million and expects to incur approximately Cdn$4.0 million for transaction costs and first-year capital expenditures. The aggregate purchase price, including linefill, transaction costs and first-year construction costs will be approximately U.S. $30.2 million, most of which, was funded from our existing Canadian credit facility.

The first section of MAPL pipeline was constructed in 1960 and other sections were constructed in 1985 and 1994. The Partnership anticipates depreciating the pipeline over forty years from the acquired date.

Imperial Oil did not make any of its employees available for possible employment with the Partnership following the completion of the acquisition. In connection with purchase, the Partnership entered into a two-year transitional services agreement with Imperial Oil whereby Imperial Oil will provide necessary services to operate the initiating pump station and the control center and software that control movements through the MAPL pipeline. The Partnership has the right to cancel the transitional services agreement at any time. The Partnership expects to assume all MAPL pipeline operations and transfer MAPL operations to the Partnership's Rangeland control center after its initiation facilities in Edmonton are constructed and operational.

The Partnership did not acquire accounting software or computer hardware with the purchase. The complex task of volumetric and revenue accounting will be consolidated with the accounting process currently in place for the Rangeland Pipeline system. The Partnership will use its existing financial accounting software for other accounting functions.

The acquisition of MAPL was accounted for as an acquisition of assets.

Purchase Price Allocations

The acquisitions of Rangeland and MAPL have been accounted for by the purchase method of accounting pursuant to Statement of Financial Accounting Standards ("FAS") No. 141, "Business Combinations" and, accordingly the consolidated statements of income include the results of Rangeland and MAPL from their acquisition dates. Based upon independent appraisals of the fair values of the acquired assets, the Partnership is completing its review and determination of the fair values of the assets acquired and liabilities assumed. Accordingly, the allocation of the purchase price is subject to revision. Based upon the preliminary estimates, the purchase price is being allocated to depreciable pipelines and related equipment, crude oil inventory, pipeline linefill, and rights of way, as well as to amortizable intangible assets. In addition to the cash purchase price and related acquisition costs, the Partnership assumed an environmental liability of approximately $2.2 million, and pursuant to FAS 109, *Accounting for Income Taxes* the Partnership recorded a deferred tax liability of $33.9 million, representing the tax effect of the difference between the amounts paid for shares of RPC, RMC and APC, and the underlying tax basis of the assets.

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 June 30, 2004 and December 31, 2003, and the statements of income for the three and six months ended June 30, 2004 and 2003 are presented below:

Balance Sheets

	June 30, 2004	December 31, 2003
	(in thousands) (unaudited)	
Current assets	$ 2,192	$ 2,013
Net property, equipment and other assets	8,758	8,901
	$ 10,950	$ 10,914
Current liabilities	$ 5,892	$ 6,313
Other liabilities	2,089	2,159
Partners' capital	2,969	2,442
	$ 10,950	$ 10,914

Statements of Income

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(in thousands) (unaudited)			
Revenue	$ 2,959	$ 2,408	$ 5,560	$ 4,538
Net income	$ 1,756	$ 1,735	$ 3,527	$ 3,271

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 June 30, 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 June 30, 2004 and December 31, 2003 are shown below:

	June 30, 2004	December 31, 2003
	(in thousands) (unaudited)	
Senior secured U.S. revolving credit facility	$ 38,000	$ 73,000
Senior secured Canadian revolving credit facility	48,731	
Senior unsecured notes, net of unamortized discount of $4,354	245,777	
Senior secured term loan		225,000
Future payment for MAPL assets	3,227	
Total	335,735	298,000
Less current portion		
Long-term debt	$ 335,735	$ 298,000

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

PEG is the borrower under the U.S. revolving credit facility. 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 June 30, 2004, $38.0 million was outstanding under the revolving credit facility. No letters of credit were issued as of that date.

The revolving credit facility matures on July 26, 2007, at which time all outstanding amounts will be due and payable.

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 now bears 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% or (ii) LIBOR plus an applicable margin ranging from 0.75% to 2.00%. The applicable margins are subject to change based on the credit rating of the revolving credit facility or, if is not rated, the credit rating of 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.

As of June 30, 2004, we had available but undrawn credit of $111 million under our U.S. revolving credit facility. This amount 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.

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

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

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 the Guarantors to, among other things, incur or guarantee indebtedness, change ownership or structure, including mergers, consolidations, liquidations and dissolutions, sell or transfer their assets and properties, declare or pay dividends and enter into a new line of business. At June 30, 2004, PEG and Guarantors were in compliance with all such covenants.

Canadian Revolving Credit Facility

On May 11, 2004, Rangeland Pipeline Company entered into a Canadian revolving credit facility agreement which is guaranteed by certain subsidiaries of PEG Canada. The maximum amount available under the Canadian revolving credit facility is Cdn$75 million, which will be further increased to Cdn$100 million after certain other conditions are satisfied. The Canadian revolving credit facility is secured by liens on all of the property and assets of Rangeland Pipeline Company and of the guarantors of the Canadian revolving credit facility.

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

The Canadian revolving credit facility matures on May 11, 2007, at which time all outstanding amounts will be due and payable. Amounts outstanding under the credit facility may be repaid at any time prior to maturity.

The Canadian revolving credit facility is available for general corporate purposes and also provides for the issuance of letters of credit. Borrowings under this facility are limited by various financial covenants that are set forth in the Canadian credit agreement. As of June 30, 2004, Rangeland Pipeline Company was in compliance with all covenants under the Canadian agreement. At June 30, 2004, borrowings totaling Cdn$65.0 million (U.S.$48.7 million) and letters of credit totaling Cdn$5.0 million (U.S.$3.7 million) were outstanding under the Canadian revolving credit facility. As of June 30, 2004, we had available but undrawn credit of Cdn$5.0 million (U.S.$3.7 million) under our Canadian revolving credit facility.

Rangeland Pipeline Company incurs a commitment or standby fee which ranges from 25% to 35% of the applicable margin, based on the unused portion of the Canadian revolving credit facility. Under the Canadian credit agreement, Rangeland Pipeline Company is prohibited from declaring dividends or making any other distributions or payments to PEG Canada or its affiliates if any default or event of default, as defined in the Canadian credit agreement, occurs or would result from such declaration or payment, or if a material adverse effect, as defined in the Canadian credit agreement, would result from such declaration or payment, or if the distributions and payments would exceed certain limits. The Canadian credit agreement also contains covenants requiring Rangeland Pipeline Company, including its subsidiaries and affiliates, to maintain specified financial ratios. In addition, the Canadian credit agreement contains other restrictive covenants. As of June 30, 2004, Rangeland Pipeline Company was in compliance with all covenants under the Canadian credit agreement.

Senior Unsecured Notes

On June 16, 2004, the Partnership and its 100% owned subsidiary Pacific Energy Finance Corporation completed the sale of $250 million of 7.125% senior unsecured notes due June 15, 2014. The notes were issued at a discount of $4.4 million, resulting in an effective interest rate of 7.375%. Interest payments are due on June 15 and December 15 of each year, beginning on December 15, 2004. At any time prior to June 15, 2007, the Partnership will have the option to redeem up to 35% of the aggregate principal amount of notes at a redemption price of 107.125% of the principal amount with the net cash proceeds of one or more equity offering. The Partnership will have the option to redeem the notes, in whole or in part, at anytime on or after June 15, 2009 at the following redemption prices:

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

The notes are jointly and severally guaranteed by certain of the partnership's subsidiaries, including PEG, PMT, RMPS, RPL, PEG Canada GP and PEG Canada.

In addition, the indenture governing the notes contains certain covenants that, among other things, limit the Partnership's ability and the ability of its restricted subsidiaries to incur or guarantee indebtedness or issue certain types of preferred equity securities; sell assets; pay distributions on, redeem or repurchase Partnership units; consolidate, merge or transfer all or substantially all of its assets. At June 30, 2004, the Partnership was in compliance with all such covenants.

Net proceeds from the issuance of the Notes were $241.1 million after deducting the $4.4 million discount and offering expenses of $4.5 million. The net proceeds were used principally to repay the Partnership's $225 million term loan and to repay $14 million of indebtedness outstanding under our U.S. revolving credit facility.

In connection with the issuance of the 7.125% Senior Notes, the Partnership entered into interest rate swap agreements with an aggregate notional principal amount of $80 million to receive interest at a fixed rate of 7.125% and to pay interest at an average variable rate of six month LIBOR plus 1.6681% (set in advance or in arrears depending on the swap transaction). See "Note 1 Summary of Significant Accounting Policies" above for further discussion on these interest rate swaps.

Future Payment for MAPL Assets

In connection with the purchase of MAPL pipeline, the Partnership is obligated to pay the seller Cdn$5.0 million (U.S.$3.7 million) on June 30, 2007. The future payment was discounted at 5%. The carrying value of the future payment was Cdn$4.3 million (U.S.$3.2 million) at June 30, 2004.

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

On June 11, 2004, in connection with the repayment of its term loan, the Partnership had a $2.3 million non-cash write-down of deferred financing costs and incurred a $0.6 million cash expense to terminate related interest rate swaps.

7. 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 were incurred in the first quarter of 2004 to fund the deposit on the Rangeland acquisition, and used approximately $76 million of the net proceeds to fund a portion of the aggregate purchase price of the Rangeland and Mid Alberta pipeline acquisitions. The Partnership utilized the remaining $31 million in net proceeds 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 Frontier 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.

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 used 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.

8. 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 and six months ended June 30, 2004 and 2003:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(in thousands) (unaudited)			
Pipeline transportation revenue:				
The Anschutz Corporation and affiliates	$ 204	$ 88	$ 373	$ 170
General and administrative expense:				
The Anschutz Corporation and affiliates	$ 35	$ 38	$ 84	$ 83

Related party balances at June 30, 2004 and December 31, 2003 were as follows:

	June 30, 2004	December 31, 2003
	(in thousands) (unaudited)	
Amounts included in accounts receivable:		
The Anschutz Corporation and affiliates	$ 156	$ 155
Amounts included in due to related parties:		
Pacific Energy GP, Inc.	$ 1,187	$ 580
The Anschutz Corporation and affiliates	6	
Total	$ 1,193	$ 580
Amounts included in undistributed long-term incentive compensation:		
Pacific Energy GP, Inc.	$ 2,003	$ 738

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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, during 2003 and the first quarter of 2004, RMPS's trucking operation hauled water for a TAC subsidiary at rates equivalent to those charged to third parties.

RMPS also receives a management fee from Frontier Pipeline in connection with time spent by RMPS management and for other services related to the pipeline's activities. RMPS received $0.1 million for each of the three months ended June 30, 2004 and 2003 and $0.3 million for each of the six months ended June 30, 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, and as amended in May 2004, the Partnership leases approximately 5,400 square feet of office space from an affiliate of TAC, for a term of five years at an annual cost of $0.1 million.

Cost Reimbursements: The General Partner employs all U.S. based employees. All employee expenses incurred by the General Partner on behalf of the Partnership are charged back 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, until mid-2003. 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.

Other: The Partnership also reimburses TAC for transportation services, based on a cost-based formula. For the six months ended June 30, 2004, the Partnership reimbursed TAC $0.1 million. No amounts were incurred for the six months ended June 30, 2003.

9. 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, PT and PMT (for the period from July 31, 2003 to June 30, 2004). Rocky Mountain operations include RMPS, RPL and PEG Canada and its Canadian subsidiaries (for the period from May 11, 2004 to June 30, 2004). 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 June 30, 2004				
Segment revenue:				
Pipeline transportation revenue	$ 16,494	$ 11,804	$ (1,306)	$ 26,992
Storage and distribution revenue(1)	9,359		(100)	9,259
Pipeline buy/sell transportation revenue(2)		3,690		3,690
Crude oil sales, net of purchases(3)	6,056			6,056
Net revenue	31,909	15,494		45,997
Expenses:				
Operating	14,182	7,907	(1,406)	20,683
Transition costs		184		184
Depreciation and amortization	3,635	2,078		5,713
Total expenses	17,817	10,169		26,580
Share of net income of Frontier		391		391
Operating income from segments(4)	14,092	5,716		19,808
Identifiable assets(5)	$ 501,424	$ 317,209		$ 818,633
Capital expenditures	$ 2,294	$ 3,185		$ 5,479
Three months ended June 30, 2003				
Segment revenue:				
Pipeline transportation revenue	$ 17,554	$ 10,321	$ (2,117)	$ 25,758
Storage and distribution revenue(1)				
Pipeline buy/sell transportation revenue(2)				
Crude oil sales, net of purchases(3)	4,979			4,979
Net revenue	22,533	10,321		30,737
Expenses:				
Operating	10,377	6,084	(2,117)	14,344
Transition costs				
Depreciation	2,859	1,346		4,205
Total expenses	13,236	7,430		18,549
Share of net income of Frontier		386		386

	West Coast Operations	Rocky Mountain Operations	Intersegment and Intrasegment Eliminations	Total
Operating income from segments(4)	9,297	3,277		12,574
Identifiable assets(5)	$ 345,391	$ 130,807		$ 476,198
Capital expenditures	$ 347	$ 284		$ 631

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	West Coast Operations	Rocky Mountain Operations	Intersegment and Intrasegment Eliminations	Total
		(in thousands) (unaudited)		
Six months ended June 30, 2004				
Segment revenue:				
Pipeline transportation revenue	$ 32,185	$ 22,347	$ (2,813)	$ 51,719
Storage and distribution revenue(1)	19,582		(200)	19,382
Pipeline buy/sell transportation revenue(2)		3,690		3,690
Crude oil sales, net of purchases(3)	10,868			10,868
Net revenue	62,635	26,037		85,659
Expenses:				
Operating	28,888	13,725	(3,013)	39,600
Transition costs		184		184
Depreciation and amortization	7,400	3,555		10,955
Total expenses	36,288	17,464		50,739
Share of net income of Frontier		784		784
Operating income from segments(4)	26,347	9,357		35,704
Identifiable assets(5)	$ 501,424	$ 317,209		$ 818,633
Capital expenditures	$ 3,420	$ 4,476		$ 7,896
Six months ended June 30, 2003				
Segment revenue:				
Pipeline transportation revenue	$ 34,888	$ 19,720	$ (3,530)	$ 51,078
Storage and distribution revenue(1)				
Pipeline buy/sell transportation revenue(2)				
Crude oil sales, net of purchases(3)	10,609			10,609
Net revenue	45,497	19,720		61,687
Expenses:				
Operating	19,796	10,726	(3,530)	26,992
Transition costs		397		397
Depreciation	5,681	2,705		8,386
Total expenses	25,477	13,828		35,775
Share of net income of Frontier		727		727
Operating income from segments(4)	20,020	6,619		26,639
Identifiable assets(5)	$ 345,391	$ 130,807		$ 476,198
Capital expenditures	$ 717	$ 474		$ 1,191

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

(2) Includes the revenue of the Canadian subsidiaries, which were acquired on May 11, 2004.

(3) The above amounts are net of purchases of $94,382 and $88,408 for the three months ended June 30, 2004 and 2003 and $175,497 and $174,700 for the six months ended June 30, 2004, respectively.

(4)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(in thousands) (unaudited)			
Income Statement Reconciliation				
Operating income from segments above:				
West Coast Operations	$ 14,092	$ 9,297	$ 26,347	$ 20,020
Rocky Mountain Operations	5,716	3,277	9,357	6,619
Operating income	19,808	12,574	35,704	26,639
Less: General and administrative	3,636	3,002	7,490	6,984
Operating income	16,172	9,572	28,214	19,655
Interest expense	(4,383)	(4,102)	(8,509)	(8,148)
Loss on extinguishment of debt	(2,901)		(2,901)	
Other income	226	156	387	247
Income before income taxes	9,114	5,626	17,191	11,754
Income tax benefit	14		14	
Net income	$ 9,128	$ 5,626	$ 17,205	$ 11,754

(5)

Identifiable segment assets do not include assets related to the Partnership's corporate activity. As of June 30, 2004 and 2003, corporate related assets were $32,879 and $9,404, respectively.

10. 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 March 9, 2004, RMPS entered into a stipulation and agreement with Sinclair, Conoco Pipe Line Company and ConocoPhillips Company that provided for a resolution of Sinclair's complaint on terms that required RMPS to incur no material cost or expense, but the effectiveness of which was subject to the satisfaction of various conditions, such as the approval of certain tariff provisions by shippers and the Federal Energy Regulatory Commission ("FERC"). All of the conditions to the effectiveness of the stipulation and agreement were satisfied during the second quarter of 2004, thereby bringing this matter to a conclusion.

The Partnership is subject to numerous federal (U.S. and Canadian), state, provincial and local laws which regulate the discharge of materials into the environment or that otherwise relate to the protection of the environment. At June 30, 2004, the Partnership had accrued for future environmental remediation liabilities of $7.6 million, including a current portion of $0.4 million, and right-of-way liabilities of $1.0 million, resulting from various acquisitions, which liabilities are classified in the accompanying 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 be expected to have a material adverse effect on its business, financial condition or results of operations.

11. SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

Given that certain, but not all subsidiaries are guarantors of our 7.125% Senior Notes, the Partnership is required to present the following supplemental condensed consolidating financial information. For purposes of the following footnote, Pacific Energy Partners, L.P. and its predecessor are referred to as "Parent." Rocky Mountain Pipeline System LLC, Pacific Marketing and Transportation LLC, Ranch Pipeline LLC, PEG Canada GP LLC, PEG Canada, L.P. and Pacific Energy Group LLC are collectively referred to as the "Guarantor Subsidiaries" and Pacific Pipeline System LLC and Pacific Terminals LLC are referred to as "Non-Guarantor Subsidiaries."

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

Balance Sheet June 30, 2004

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
			(in thousands)		
Assets:					
Current asssets	$ 8,772	$ 85,661	$ 34,220	$ (32,656)	$ 95,997
Property and equipment		128,925	576,123		705,048
Equity investments	372,088	200,773		(566,044)	6,817
Intercompany notes receivable	295,487	330,952		(626,439)	
Other assets	4,668	2,269	36,713		43,650
Total assets	$ 681,015	$ 748,580	$ 647,056	$ (1,225,139)	$ 851,512
Liabilities and partners' capital:					
Current liabilities	$ 12,799	$ 42,583	$ 27,512	$ (32,656)	$ 50,238
Long-term debt	245,777	38,000	51,958		335,735
Deferred income taxes			34,928		34,928
Intercompany notes payable		295,487	330,952	(626,439)	
Other liabilities		422	7,750		8,172
Total partners' capital	422,439	372,088	193,956	(566,044)	422,439
Total liabilities and partners' capital	$ 681,015	$ 748,580	$ 647,056	$ (1,225,139)	$ 851,512

Balance Sheet December 31, 2003

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating adjustments	Total
	(in thousands)				
Assets:					
Current asssets	$ 2,799	$ 63,905	$ 17,168	$ (15,076)	$ 68,796
Property and equipment		126,216	441,738		567,954
Equity investments	292,268	165,815		(451,197)	6,886
Intercompany notes receivable		276,400		(276,400)	
Other assets		4,957	1,610		6,567
Total assets	$ 295,067	$ 637,293	$ 460,516	$ (742,673)	$ 650,203
Liabilities and partners' capital:					
Current liabilities	$	$ 45,980	$ 19,087	$ (15,076)	$ 49,991
Long-term debt		298,000			298,000
Intercompany notes payable			276,400	(276,400)	
Other liabilities		1,045	6,100		7,145
Total partners' capital	295,067	292,268	158,929	(451,197)	295,067
Total liabilities and partners' capital	$ 295,067	$ 637,293	$ 460,516	$ (742,673)	$ 650,203

Statement of Income Three Months Ended June 30, 2004

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands)				
Operating revenues	$	$ 17,859	$ 29,544	$ (1,406)	$ 45,997
Operating expenses		(10,038)	(12,235)	1,406	(20,867)
General and administrative expense(1)		(3,390)	(246)		(3,636)
Depreciation and amortization expense		(1,648)	(4,065)		(5,713)
Share of net income of Frontier		391			391
Operating income		3,174	12,998		16,172
Interest expense	(754)	(3,294)	(335)		(4,383)
Intercompany interest income (expense)		4,871	(4,871)		
Equity earnings	9,878	7,864		(17,742)	
Interest and other income	4	(2,737)	58		(2,675)
Income tax benefit			14		14
Net income	$ 9,128	$ 9,878	$ 7,864	$ (17,742)	$ 9,128

(1) General and administrative expense is not currently allocated between guarantor and non-guarantor subsidiaries for financial reporting purposes.

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Statement of Income Three Months Ended June 30, 2003

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
			(in thousands)		
Operating revenues	$	$ 15,300	$ 17,554	$ (2,117)	$ 30,737
Operating expenses and transition costs		(10,423)	(6,038)	2,117	(14,344)
General and administrative expense(1)	(6)	(2,972)	(24)		(3,002)
Depreciation and amortization expense		(1,453)	(2,752)		(4,205)
Share of net income of Frontier		386			386
Operating income	(6)	838	8,740		9,572
Interest expense		(4,102)			(4,102)
Intercompany interest income (expense)		1,759	(1,759)		
Equity earnings	5,625	6,996		(12,621)	
Interest and other income	7	134	15		156
Net income	$ 5,626	$ 5,625	$ 6,996	$ (12,621)	$ 5,626

(1) General and administrative expense is not currently allocated between guarantor and non-guarantor subsidiaries for financial reporting purposes.

Statement of Income Six Months Ended June 30, 2004

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
			(in thousands)		
Operating revenues	$	$ 33,215	$ 55,457	$ (3,013)	$ 85,659
Operating expenses and transition costs		(19,738)	(23,059)	3,013	(39,784)
General and administrative expense(1)		(7,218)	(272)		(7,490)
Depreciation and amortization expense		(3,243)	(7,712)		(10,955)
Share of net income of Frontier		784			784
Operating income		3,800	24,414		28,214
Interest expense	(754)	(7,420)	(335)		(8,509)
Intercompany interest income (expense)		8,618	(8,618)		
Equity earnings	17,954	15,574		(33,528)	
Interest and other income	5	(2,618)	99		(2,514)
Income tax benefit			14		14
Net income	$ 17,205	$ 17,954	$ 15,574	$ (33,528)	$ 17,205

(1)

General and administrative expense is not currently allocated between guarantor and non-guarantor subsidiaries for financial reporting purposes.

Statement of Income Six Months Ended June 30, 2003

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
			(in thousands)		
Operating revenues	$	$ 30,329	$ 34,888	$ (3,530)	$ 61,687
Operating expenses and transition costs		(19,184)	(11,735)	3,530	(27,389)
General and administrative expense(1)	(6)	(6,927)	(51)		(6,984)
Depreciation and amortization expense		(2,906)	(5,480)		(8,386)
Share of net income of Frontier		727			727
Operating income	(6)	2,039	17,622		19,655
Interest expense		(8,148)			(8,148)
Intercompany interest income (expense)		3,608	(3,608)		
Equity earnings	11,747	14,047		(25,794)	
Interest and other income	13	201	33		247
Net income	$ 11,754	$ 11,747	$ 14,047	$ (25,794)	$ 11,754

(1) General and administrative expense is not currently allocated between guarantor and non-guarantor subsidiaries for financial reporting purposes.

Statement of Comprehensive Income Three Months Ended June 30, 2004

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
			(in thousands)		
Net income	$ 9,128	$ 9,878	$ 7,864	$ (17,742)	$ 9,128
Change in fair value of hedging derivatives	9,140	9,140		(9,140)	9,140
Foreign currency translation adjustment	2,429	2,423	6	(2,429)	2,429
Comprehensive income	$ 20,697	$ 21,441	$ 7,870	$ (29,311)	$ 20,697

Statement of Comprehensive Income Three Months Ended June 30, 2003

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
			(in thousands)		
Net income	$ 5,626	$ 5,625	$ 6,996	$ (12,621)	$ 5,626
Change in fair value of hedging derivatives	(4,127)	(4,127)		4,127	(4,127)
Comprehensive income	$ 1,499	$ 1,498	$ 6,996	$ (8,494)	$ 1,499

Statement of Comprehensive Income Six Months Ended June 30, 2004

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
			(in thousands)		
Net income	$ 17,205	$ 17,954	$ 15,574	$ (33,528)	$ 17,205
Change in fair value of hedging derivatives	4,904	4,904		(4,904)	4,904
Foreign currency translation adjustment	2,429	2,423	6	(2,429)	2,429
Comprehensive income	$ 24,538	$ 25,281	$ 15,580	$ (40,861)	$ 24,538

Statement of Comprehensive Income Six Months Ended June 30, 2003

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
			(in thousands)		
Net income	$ 11,754	$ 11,747	$ 14,047	$ (25,794)	$ 11,754
Change in fair value of hedging derivatives	(4,988)	(4,988)		4,988	(4,988)
Comprehensive income	$ 6,766	$ 6,759	$ 14,047	$ (20,806)	$ 6,766

Statement of Cash Flows Six Months Ended June 30, 2004

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
			(in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net income	$ 17,205	$ 17,954	$ 15,574	$ (33,528)	$ 17,205
Adjustments to reconcile net income to net cash provided by operating activities:					
Equity earnings	(17,954)	(15,574)		33,528	
Distributions from subsidiaries	27,081	22,927		(50,008)	
Depreciation, amortization and other	22	7,401	7,712		15,135
Net changes in operating assets and liabilities	1,414	(8,619)	(8,193)	12,930	(2,468)
NET CASH PROVIDED BY OPERATING ACTIVITIES	27,768	24,089	15,093	(37,078)	29,872
CASH FLOWS FROM INVESTING ACTIVITIES					
Acquisitions			(139,050)		(139,050)
Additions to property and equipment		(5,751)	(2,145)		(7,896)
Intercompany	(369,657)	(91,155)		460,812	
NET CASH USED IN INVESTING ACTIVITIES	(369,657)	(96,906)	(141,195)	460,812	(146,946)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	343,915	81,184	127,871	(423,734)	129,236
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	2,026	8,367	1,769		12,162
CASH AND CASH EQUIVALENTS, beginning of reporting period	746	8,603	350		9,699
CASH AND CASH EQUIVALENTS, end of reporting period	$ 2,772	$ 16,970	$ 2,119	$	$ 21,861

	Statement of Cash Flows Six Months Ended June 30, 2003				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands)				
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net income	$ 11,754	$ 11,747	$ 14,047	$ (25,794)	$ 11,754
Adjustments to reconcile net income to net cash provided by operating activities:					
Equity earnings	(11,747)	(14,047)		25,794	
Distributions from subsidiaries	19,755	19,337		(39,092)	
Depreciation, amortization and other		5,912	5,480		11,392
Net changes in operating assets and liabilities	42	(2,147)	(1,378)	(489)	(3,972)
NET CASH PROVIDED BY OPERATING ACTIVITIES	19,804	20,802	18,149	(39,581)	19,174
CASH FLOWS FROM INVESTING ACTIVITIES					
Acquisitions					
Additions to property, equipment and other		(685)	(459)		(1,144)
Intercompany					
NET CASH USED IN INVESTING ACTIVITIES		(685)	(459)		(1,144)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	(19,669)	(22,380)	(17,287)	39,581	(19,755)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	135	(2,263)	403		(1,725)
CASH AND CASH EQUIVALENTS, beginning of reporting period	2,394	13,285	8,194		23,873
CASH AND CASH EQUIVALENTS, end of reporting period	$ 2,529	$ 11,022	$ 8,597	$	$ 22,148

11. SUBSEQUENT EVENT

On July 19, 2004, the Partnership announced a cash distribution of $0.4875 per limited partner unit, payable on August 13, 2004, to unitholders of record as of July 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 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 ("RMP"), owner of the Partnership's interest in various pipelines that make up the Western Corridor system, and 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").

The unaudited condensed consolidated balance sheet, statement of income and statements of cash flows of the Partnership also include our 100% ownership interest in PEG Canada GP LLC, the general partner of PEG Canada, L.P. ("PEG Canada"), the operating company of our Canadian subsidiaries. We own 100% of the limited partner interests in PEG Canada, whose 100% subsidiaries consist of (i) Rangeland Pipeline Company ("RPC"), which owns 100% of Aurora Pipeline Company Ltd. ("APC") and a partnership interest in Rangeland Pipeline Partnership ("RPP"), (ii) Rangeland Northern Pipeline Company ("RNPC"), which owns the remaining partnership interest in RPP, and (iii) Rangeland Marketing Company ("RMC"). RPP owns all of the assets that make up the Rangeland and Mid-Alberta pipeline systems except the Aurora pipeline, which is owned by APC.

We also own 100% of Pacific Energy Finance Corporation, co-issuer on our 7.125% Senior Notes.

PPS, PT and PMT comprise our West Coast operations segment. RMPS, RPL, PEG Canada, RPC, APC, RPP, RNPC and RMC 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 June 30, 2004; the ownership and results of operations of Rangeland Pipeline system for the period May 11, 2004 to June 30, 2004; and the ownership of MAPL for the last day of the period ended June 30, 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 related products in California and the Rocky Mountain region, including Alberta, Canada. We generate revenue primarily by charging tariff rates for transporting crude oil on our pipelines and by leasing storage capacity. We also buy, blend and sell crude oil, activities that are complementary to our pipeline transportation business. We operate primarily in California, Colorado, Montana, Wyoming and Utah in the United States and in Alberta, Canada and conduct our business through two regional operating units: West Coast operations and Rocky Mountain operations.

We are managed by our general partner, Pacific Energy GP, Inc., a wholly owned indirect subsidiary of The Anschutz Corporation.

West Coast Operations

Our West Coast operations are located in California and include the only common carrier pipelines that deliver crude oil produced in California's San Joaquin Valley and the two primary California Outer Continental Shelf ("OCS") producing fields, Point Arguello and the Santa Ynez Unit, to refineries and terminal facilities in the Los Angeles Basin and in Bakersfield. In addition, we own and operate storage and distribution assets servicing the Los Angeles Basin, which we believe 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") that transports crude oil produced in the San Joaquin Valley and California OCS to refineries and terminal facilities in the Los Angeles Basin.

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.

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 storage 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.

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 five storage and blending facilities with a total of approximately 0.25 million barrels of storage capacity and up to 51,000 bpd of blending capacity. The PMT gathering and blending system is interconnected to our Line 63 system. Pacific Marketing and Transportation LLC buys, blends and sells crude oil, activities that are complementary to our pipeline transportation business.

Rocky Mountain Operations

Our Rocky Mountain operations consist of various interests in pipelines that transport crude oil produced in Canada and the U.S. Rocky Mountain region to refineries in Montana, Wyoming, Colorado and Utah. We deliver crude oil to these refineries directly through our pipelines or indirectly through connections with third-party pipelines. Our Rocky Mountain operations are headquartered in Denver, Colorado and Calgary, Alberta. We have five field offices in Wyoming and two in Alberta.

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

Rangeland and MAPL System: The Rangeland system includes MAPL pipeline and the Rangeland Pipeline system. The MAPL pipeline is a 138-mile proprietary pipeline with a throughput capacity of approximately 50,000 bpd if transporting light crude oil. MAPL pipeline originates at Edmonton, Alberta and terminates in Sundre, Alberta, where it connects to the Rangeland Pipeline system. The Rangeland Pipeline system is a proprietary pipeline system that consists of approximately 800 miles of gathering and trunk pipelines and is capable of transporting crude oil, condensate and butane either north to Edmonton, Alberta via third-party pipeline connections or south to the U.S.-Canadian border near Cutbank, Montana where it connects to the Western Corridor system. The trunk pipeline from Sundre, Alberta to the U.S.-Canadian border consists of approximately 250 miles of trunk pipelines and has a current throughput capacity of approximately 85,000 bpd if transporting light crude oil. In 2003, approximately 47,000 barrels per day were transported on the trunk pipeline. The trunk system from Sundre, Alberta north to Rimbey, Alberta is a bi-directional system that consists of three parallel trunk pipelines for low sulfur crude oil, high sulfur crude oil, and for condensate and butane, each approximately 60 miles in length.

Over the next year, the Partnership will construct a new initiating terminal facility with multiple pipeline connections in Edmonton, Alberta. In the interim, current volumes of approximately 7,000 bpd are expected to continue being transported on MAPL pipeline. The Rangeland Pipeline system will transport these volumes plus its current volumes of approximately 38,000 bpd for a total volume of 45,000 bpd south to the United States. In addition, approximately 20,000 bpd will continue to be gathered and transported north to Edmonton, Alberta.

In effect, the Partnership is converting what is now primarily a gathering system for crude oil, condensate and butane in southern Alberta into a main line transportation system, able to transport multiple grades of conventional and synthetic crude oils from the Edmonton oil hub to U.S. Rocky Mountain refining centers.

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 U.S.-Canadian border near Cutbank, Montana, where it receives deliveries from the Rangeland system, 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 the Salt Lake City Core system. The Western Corridor 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 U.S.-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 914 miles of trunk pipelines with a combined throughput capacity of approximately 60,000 bpd to Salt Lake City, 209 miles of gathering pipelines, and 30 storage tanks with a total of approximately 1.5 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. Upon completion of a new connection in July 2004, the Salt Lake City Core system also receives deliveries 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 AREPI pipeline and to the Salt Lake City Core system (beginning July 2004) 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 own and operate 100% of AREPI pipeline.

Key Events in the Three and six Months Ended June 30, 2004

Canadian Acquisitions

Rangeland System Acquisition. On May 11, 2004, we completed the acquisition of the Rangeland Pipeline system from BP Canada Energy Company ("BP Canada"). The Rangeland Pipeline system is located in Alberta, Canada. The acquisition price for the Rangeland Pipeline system was Cdn$130 million plus approximately Cdn$29 million for linefill, working capital, transaction costs and transition capital expenditures for an aggregate purchase price of Cdn$159 million or US$116 million.

MAPL Pipeline Acquisition. On June 30, 2004, we completed the acquisition of the Mid Alberta Pipeline ("MAPL"), located in Alberta, Canada from Imperial Oil. The acquisition price for MAPL is Cdn$31.5 million, of which Cdn$5.0 million is payable in three years. In addition, we acquired linefill for Cdn$5.0 million and expect to incur approximately Cdn$4.0 million for first year capital expenditures, as noted below, and transaction costs. The aggregate purchase price including linefill, first year construction costs and transaction costs is approximately US$30.2 million and was funded principally from our Canadian credit facilities.

Integration and Transition. The Rangeland Pipeline system and MAPL pipeline have each historically been operated on a proprietary basis. We intend to make significant changes to the revenue-generating capability of these assets by combining and integrating fully all of our Canadian and U.S. Rocky Mountain pipeline assets under common management, by expanding the throughput capacity of MAPL pipeline by establishing connections with other pipelines, and by constructing a pump station and receiving terminal in Edmonton, Alberta. This new pump station and receiving terminal will be able to access multiple sources of Canadian crude oil, which will allow us to participate in the projected increase in production of synthetic crude oil. The construction of the new connections on MAPL pipeline and the new pump station and receiving terminal is expected to cost approximately Cdn$4.0 million, and is expected to be completed in the third quarter of 2005.

Financing. We funded the aggregate purchase price, including transaction costs, for the Rangeland Pipeline system and MAPL with a portion of the net proceeds from our March 2004 issuance of common units and Cdn$65 million in borrowings under our new Cdn$100 million revolving credit facility.

Pier 400

In February 2004, we completed a feasibility study for the development of a deepwater petroleum import terminal at Pier 400 and Terminal Island in the Port of Los Angeles ("POLA") to handle marine receipts of crude oil and refinery feedstocks. We are continuing to the next phase of development of the Pier 400 terminal, commencing with the environmental review, which is expected to be completed by late 2005. In connection with this next phase of development, we entered into a project development agreement with two subsidiaries of Valero Energy Corporation ("Valero") that defines the facilities that we are to construct in the POLA, 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 terminal. In addition, we and the POLA have identified several possible sites for construction of storage facilities and have agreed to begin the review process required by the California Environmental Quality Act.

If the Pier 400 terminal receives the necessary governmental approvals and is successfully developed, a deepwater berth, transfer infrastructure and storage tanks will be constructed at Pier 400 and Terminal Island in the POLA and a pipeline distribution system will be constructed to connect the terminal's storage tanks to Valero's Wilmington refinery and to our customers' facilities in the Los Angeles Basin through our Pacific Terminals storage and distribution system. We would construct the transfer infrastructure, including a large diameter pipeline system for receiving bulk petroleum liquids from marine vessels, storage tanks with an initial storage capacity of approximately 1.5 million barrels, and a pipeline distribution system, all at an estimated cost of approximately $130 million. The deepwater berth at Pier 400 would be constructed by the POLA.

The Pier 400 terminal 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 waterborne imported crude oil and refinery feedstocks. Initially, the Pier 400 terminal is expected to handle marine receipts of approximately 100,000 bpd. However, the receipt facilities are being designed, subject to permit limitations, to accommodate up to approximately 250,000 bpd. We expect construction of the Pier 400 terminal to be completed and placed in service in early 2007.

We have spent and capitalized approximately $1.8 million on the Pier 400 terminal in 2004 and $5.3 million in 2003. We expect to incur additional capital expenditures of approximately $1.2 million during the remainder of 2004. We anticipate funding pre-construction costs through mid-2005 from a portion of the proceeds from our March 2004 issuance of common units. Construction of the Pier 400 terminal is expected to be financed through a combination of debt and proceeds from the issuance of additional limited partner interests, including common units.

Salt Lake City Expansion Project

In July 2004, we completed the expansion of our pipelines serving Salt Lake City by establishing a new delivery connection from Frontier pipeline to the Salt Lake City Core system. The expansion cost approximately $3.1 million. Existing pipelines into Salt Lake City have recently been prorated, or limited by capacity, during the summer season. This connection increased delivery capacity to Salt Lake City refineries by approximately 9,000 bpd.

Equity and Debt Offerings

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

On June 16, 2004, the Partnership and its 100% owned subsidiary Pacific Energy Finance Corporation completed the sale of $250 million of 7.125% senior unsecured notes due June 15, 2014. The notes were issued at a discount of $4.4 million, resulting in an effective interest rate of 7.375%. Net proceeds from the issuance of the Notes were $241.1 million after deducting the $4.4 million discount and offering expenses of $4.5 million. The net proceeds were used principally to repay the Partnership's $225 million term loan and to repay $14 million of indebtedness outstanding under our U.S. revolving credit facility.

In connection with the issuance of the notes, the Partnership entered into interest rate swap agreements with an aggregate notional principal amount of $80 million to receive interest at a fixed rate of 7.125% and to pay interest at an average variable rate of six month LIBOR plus 1.6681% (set in advance or in arrears depending on the swap transaction). The net impact of the notes offering, the related interest rate swap and the term loan repayment is that the Partnership expects its interest expense to remain largely unchanged.

Business Fundamentals

Pipeline Transportation

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

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

The availability of crude oil for transportation on our pipelines is dependent in part on the amount of drilling and enhanced recovery activity in the production fields we serve in our West Coast operations and in parts of our Rocky Mountain operations. With the passage of time, production of crude oil in an individual well naturally declines, which can in the short-term be offset in whole or in part by additional drilling or the implementation of recovery enhancement measures. In the San Joaquin Valley and in the California OCS, production is generally declining. The expected development of the Rocky Point field in the California OCS and, if it occurs, the closure of the Shell Bakersfield refinery, will, we believe, increase 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 terminal 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 completed the acquisitions of pipeline systems giving us greater access to significant supplies of Canadian crude oil, including synthetic crude oil, which we believe will replace any Rocky Mountain production decline and meet growing demand in the Rocky Mountain region.

The tariff rates we charge on Line 2000 and the Line 63 system are regulated by the California Public Utilities Commission (the "CPUC"). Tariffs on Line 2000 are established based on market considerations, subject to certain contractual 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 U.S. 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); we currently await permit approvals for one such tank conversion.

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

Pipeline Buy/Sell Transportation Revenue

The Rangeland and MAPL system operates as a proprietary system, and accordingly we take title to the crude oil that is gathered and transported. Pursuant to a transportation service agreement between Rangeland Marketing Company and Rangeland Pipeline Company, Rangeland Marketing Company has contracted for the entire capacity of the Rangeland pipeline. Customers who wish to transport product on the Rangeland pipeline may either: (i) sell product to Rangeland Marketing Company at the inlet to the pipeline without repurchasing product from Rangeland Marketing Company; or (ii) sell product to Rangeland Marketing Company at an inlet point and repurchase such product at agreed upon delivery points for the price paid at the inlet to the pipeline plus an established location differential.

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

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 Expenses

A substantial portion of the operating expenses we incur, including the cost of field and support personnel, maintenance, control systems, telecommunications, rights-of-way and insurance, varies little with changes in throughput. Certain of our costs, however, do vary with throughput, the most material being the cost of power used to run 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 release of oil to the extent not covered by insurance.

Employees

We do not have any employees, except in Canada. Our general partner, which employs U.S. employees, and our Canadian subsidiaries employ approximately 300 employees who directly support our operations. Our general partner and our Canadian subsidiaries consider their employee relations to be good. None of these employees are subject to a collective bargaining agreement. Our general partner does not conduct any business other than with respect to the partnership. All expenses incurred by our general partner are charged to us.

Impact of Foreign Exchange Rates

The cash flow of our Canadian operations is based on the U.S. dollar equivalent of such amounts measured in Canadian dollars. Assets and liabilities of our Canadian subsidiaries are translated to U.S. dollars using the applicable exchange rate as of the end of a reporting period. Revenues, expenses and cash flow are translated using the average exchange rate during the reporting period. The results of our Canadian operations and distributions from our Canadian subsidiaries to our U.S. company may vary based on fluctuations in currency exchange rates irrespective of our Canadian subsidiaries underlying operating results.

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 Summary of 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. We are exposed to the potential for a write-down to market value. A write-down will likely occur in future years as oil prices tend to be cyclical. However, 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 June 30, 2004 Compared to Three Months Ended June 30, 2003

Summary

	Three Months Ended June 30,			
	2004	2003	Change	Percent
	(In thousands) (unaudited)			
Net income	$ 9,128	$ 5,626	$ 3,502	62%
Net income per limited partner unit				
Basic and diluted	$ 0.30	$ 0.26	$ 0.04	15%
Recurring net income	$ 12,029(1)	$ 5,626	$ 6,403	114%
Recurring net income per limited partner unit				
Basic and diluted	$ 0.40	$ 0.26	$ 0.14	54%

(1) Excludes expense of $2.9 million incurred in connection with the repayment of our term loan, including a $2.3 million non-cash write-off of deferred financing costs and a $0.6 million cash expense for related interest rate swap terminations.

Net income for the three months ended June 30, 2004 includes the operations of the Pacific Terminals storage and distribution system following the acquisition of these assets on July 31, 2003 and the operations of Rangeland Pipeline system after acquiring these assets on May 11, 2004. Net income also reflects a $2.9 million expense incurred in connection with the repayment of our term loan, including a $2.3 non-cash write-down of previously deferred financing costs and a $0.6 million to terminate interest rate swap agreements.

The increase in recurring net income reflects the benefit of (i) the operation, since July 31, 2003, of the Pacific Terminals storage and distribution system, (ii) higher margins in gathering and blending operations, (iii) higher volumes and revenue on the Rocky Mountain pipelines and (iv) the operations of the Rangeland Pipeline system acquired in May 2004. These increases were partially offset by lower volumes and revenue from the West coast pipelines. There were approximately 40% more limited partner units outstanding in the three months ended June 30, 2004 due to the sale of additional common units to partially fund the acquisitions of the Pacific Terminals storage and distribution system, the Rangeland Pipeline system and MAPL pipeline.

Segment Information

West Coast	Three Months Ended June 30, 2004	2003	Change	Percent
	(In thousands) (unaudited)			
Operating income	$ 14,092	$ 9,297	$ 4,795	52%
Operating data:				
Pipeline throughput (bpd)	139.5	156.5	(17.0)	-11%

The increase in West Coast operating income was primarily due to the acquisition of the Pacific Terminals storage and distribution system and higher margins in the gathering and blending operations, partially offset by a reduction in pipeline transportation revenue as average daily pipeline throughput decreased to 139,500 barrels per day for the three months ended June 30, 2004, compared to 156,500 barrels per day for the corresponding period of the prior year. Throughput volumes during the second quarter of this year were adversely affected by refinery maintenance as well as by reduced California Outer Continental Shelf ("OCS") volumes due to third party field maintenance and natural decline.

Rocky Mountains	Three Months Ended June 30, 2004	2003	Change	Percent
	(In thousands) (unaudited)			
Operating income	$ 5,716	$ 3,277	$ 2,439	74%
Operating data (bpd):				
Rangeland pipeline system				
Sundre North	21.2		n.a.	n.a.
Sundre South	48.8		n.a.	n.a.
Western Corridor system	19.8	17.6	2.2	13%
Salt Lake City Core system	73.0	64.7	8.3	13%
AREPI pipeline	46.2	41.4	4.8	12%
Frontier pipeline	50.0	41.0	9.0	22%

Operating income increased due to higher volumes on the Western Corridor system, and increased volumes on the systems that transport oil into the Salt Lake City area. The increase into Salt Lake City reflects increased demand compared to the prior quarter due to refinery turnarounds last year. In addition, the Rangeland Pipeline system was acquired on May 11, 2004.

Statement of Income Discussion and Analysis

	Three Months Ended June 30, 2004	2003	Change	Percent
	(In thousands) (unaudited)			
Pipeline transportation revenue	$ 26,992	$ 25,758	$ 1,234	5%

Lower West Coast pipeline revenues due to refinery maintenance activities in California, coupled with a decline of California OCS volumes, were more than 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, as well as by higher tariffs in California.

	Three Months Ended June 30,			
	2004	2003	Change	Percent
	(In thousands) (unaudited)			
Storage and distribution revenue	$ 9,259	$	$ 9,259	

The acquisition of the Pacific Terminals storage and distribution system on July 31, 2003 resulted in storage and distribution revenue of $9.3 million for the three months ended June 30, 2004.

	Three Months Ended June 30,			
	2004	2003	Change	Percent
	(In thousands) (unaudited)			
Pipeline buy/sell transportation revenue	$ 3,690	$	$ 3,690	

Pipeline buy/sell transportation revenues of $3.7 million relate to the operations of the Rangeland pipeline system which was acquired on May 11, 2004.

	Three Months Ended June 30,			
	2004	2003	Change	Percent
	(In thousands) (unaudited)			
Crude oil sales	$ 100,438	$ 93,387	$ 7,051	8%
Crude oil purchases	(94,382)	(88,408)	5,974	7%
Crude oil sales, net of purchases	$ 6,056	$ 4,979	$ 1,077	22%

The increase in net crude oil sales for the three months ended June 30, 2004 was primarily the result of higher margin blending activities offset by lower blending volumes as a result of change in refined products specifications. We consider this activity to be complementary to our pipeline transportation operations.

	Three Months Ended June 30,			
	2004	2003	Change	Percent
	(In thousands) (unaudited)			
Operating expenses	$ 20,683	$ 14,344	$ 6,339	44%

The increase in operating expense was related primarily to the acquisition of the Pacific Terminals storage and distribution assets in July 2003 and the Rangeland pipeline system in May 2004. We also experienced higher maintenance and power costs in the Rocky Mountains as a result of the timing of internal line inspections and increased power costs as a result of higher volumes and increased natural gas prices.

	Three Months Ended June 30,			
	2004	2003	Change	Percent
	(In thousands) (unaudited)			
Transition costs	$ 184	$	$ 184	

Transition costs were incurred for transition services provided by the seller, as well as for consulting and other out-of-pocket costs incurred in connection with the integration of the Rangeland pipeline system.

	Three Months Ended June 30,			
	2004	2003	Change	Percent
	(In thousands) (unaudited)			
General and administrative expense	$ 3,636	$ 3,002	$ 634	21%

The increase in general and administrative expense was mainly attributable to higher personnel costs associated with growth of the Partnership and increased consulting and outside services associated with statutory compliance activities.

	Three Months Ended June 30,			
	2004	2003	Change	Percent
	(In thousands) (unaudited)			
Depreciation and amortization	$ 5,713	$ 4,205	$ 1,508	36%

The increase in depreciation and amortization includes $0.9 million for depreciation on the Pacific Terminals storage and distribution system and $0.5 million for depreciation on the Rangeland pipeline system.

	Three Months Ended June 30,			
	2004	2003	Change	Percent
	(In thousands) (unaudited)			
Share of net income of Frontier	$ 391	$ 386	$ 5	1%

Our increased share of Frontier net income was attributable to increased volumes on Frontier pipeline, offset by increased expenses for flow improver, power and legal services.

Three Months Ended June 30,			
2004	2003	Change	Percent

	Three Months Ended June 30,			
		(In thousands) (unaudited)		
Interest expense	$ 4,383	$ 4,102	$ 281	7%

The increase in interest expense was mainly due to an increase in borrowings incurred to partially fund the acquisition of Pacific Terminals storage and distribution system and the Rangeland pipeline system. Our weighted average borrowings during the three months ended June 2004 were $273 million compared to $225 million in the corresponding period in 2003. However, the increase in borrowings was offset by a lower weighted average interest rate of 6.0% for the three months ended June 30, 2004 compared to a weighted average interest rate of 7.3% 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.

	Three Months Ended June 30, 2004	Three Months Ended June 30, 2003	Change	Percent
	(In thousands) (unaudited)			
Write-off of deferred financing costs and interest rate swap termination expense	$ 2,901	$	$ 2,901	

The amount relates to the write-off of deferred financing costs of $2,324 incurred in connection with the repayment of our term loan and $577 of expense incurred to terminate related interest rate swaps.

	Three Months Ended June 30, 2004	Three Months Ended June 30, 2003	Change	Percent
	(In thousands) (unaudited)			
Income tax expense (benefit):				
Current	$ 32		$ 32	
Deferred	(46)		(46)	
	$ (14)		$ (14)	

The income taxes relate to the Canadian income of the Rangeland pipeline system acquired in May 2004.

Six Months Ended June 30, 2004 Compared to Six Months Ended June 30, 2003

Summary

	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003	Change	Percent
	(In thousands) (unaudited)			
Net income	$ 17,205	$ 11,754	$ 5,451	46%
Net income per limited partner unit				
Basic and diluted	$ 0.62	$ 0.55	$ 0.07	13%
Recurring net income	$ 20,106(1)	$ 11,754	$ 8,352	71%
Recurring net income per limited partner unit				
Basic and diluted	$ 0.72	$ 0.55	$ 0.17	31%

(1)

Excludes expense of $2.9 million incurred in connection with the repayment of our term loan, including a $2.3 million non-cash write-off of deferred financing costs and a $0.6 million cash expense for related interest rate swap terminations.

Net income for the six months ended June 30, 2004 includes the operations of the Pacific Terminals storage and distribution system following the acquisition of these assets on July 31, 2003 and the operations of Rangeland Pipeline system after acquiring these assets on May 11, 2004. Net income also reflects a $2.9 million expense incurred in connection with the repayment of our term loan, including a $2.3 non-cash write-down of previously deferred financing costs and a $0.6 million to terminate interest rate swap agreements.

The increase in recurring net income reflects the benefit of (i) the operation, since July 2003, of Pacific Terminals storage and distribution system, (ii) higher volumes and revenue on the Rocky Mountain pipelines, (iii) the operations of the Rangeland Pipeline system acquired in May 2004, and (iii) increased gathering and blending margins. These increases were partially offset by lower volumes and revenue from the West coast pipelines. There were approximately 30% more limited partner units outstanding in the six months ended June 30, 2004 due to the sale of additional common units to partially fund the acquisitions of the Pacific Terminals storage and distribution system, the Rangeland Pipeline system and MAPL pipeline.

Segment Information

West Coast	Six Months Ended June 30, 2004	2003	Change	Percent
		(In thousands) (unaudited)		
Operating income	$ 26,347	$ 20,020	$ 6,327	32%
Operating data:				
Pipeline throughput (bpd)	136.6	157.9	(21.3)	-13%

The increase in West Coast operating income was primarily due to the acquisition of the Pacific Terminals storage and distribution system. In addition, we experienced higher margins in our gathering and blending operations. This increase was partially offset by a reduction in pipeline transportation revenue as average daily pipeline throughput decreased to 136,600 barrels per day for the six months ended June 30, 2004, compared to 157,900 barrels per day for the corresponding period of the prior year. Throughput volumes during the first six months of this year were adversely affected by refinery maintenance activities. In addition, OCS volumes were lower due to natural field decline.

Rocky Mountains	Six Months Ended June 30, 2004	2003	Change	Percent
		(In thousands) (unaudited)		
Operating income	$ 9,357	$ 6,619	$ 2,738	41%
Operating data (bpd):				
Rangeland pipeline system				
Sundre North	21.2		n.a.	n.a.
Sundre South	48.8		n.a.	n.a.
Western Corridor system	18.0	15.6	2.4	15%
Salt Lake City Core system	67.9	64.7	3.2	5%
AREPI pipeline	45.1	38.5	6.6	17%
Frontier pipeline	47.0	38.2	8.8	23%

The increase in Rocky Mountains operating income was primarily due to increased demand by refineries in the Salt Lake City area this year, compared to 2003 when demand was lower due to refinery turnarounds. In addition, we acquired the Rangeland pipeline system on May 11, 2004.

Statement of Income Discussion and Analysis

	Six Months Ended June 30,			
	2004	2003	Change	Percent
	(In thousands) (unaudited)			
Pipeline transportation revenue	$ 51,719	$ 51,078	$ 641	1%

Higher Rocky Mountain pipeline revenues due to increased demand by Salt Lake City area refineries were mostly offset by lower West Coast pipeline revenues due to refinery maintenance activities in California.

	Six Months Ended June 30,			
	2004	2003	Change	Percent
	(In thousands) (unaudited)			
Storage and distribution revenue	$ 19,382	$	$ 19,382	

The acquisition of the Pacific Terminals storage and distribution system on July 31, 2003 resulted in storage and distribution revenue of $19.4 million for the six months ended June 30, 2004.

	Six Months Ended June 30,			
	2004	2003	Change	Percent
	(In thousands) (unaudited)			
Pipeline buy/sell transportation revenue	$ 3,690	$	$ 3,690	

Pipeline buy/sell transportation revenues of $3.7 million relate to the operations of the Rangeland pipeline system which was acquired on May 11, 2004.

	Six Months Ended June 30,			
	2004	2003	Change	Percent
	(In thousands) (unaudited)			
Crude oil sales	$ 186,365	$ 185,309	$ 1,056	1%
Crude oil purchases	(175,497)	(174,700)	797	1%
Crude oil sales, net of purchases	$ 10,868	$ 10,609	$ 259	2%

The increase in net crude oil sales for 2004 was primarily the result of higher margin blending activities offset by lower blending volumes as a result of change in refined products specifications. We consider this activity to be complementary to our pipeline transportation operations.

	Six Months Ended June 30,			
	2004	2003	Change	Percent
	(In thousands) (unaudited)			
Operating expenses	$ 39,600	$ 26,992	$ 12,608	47%

The increase in operating expense was related primarily to the acquisition of the Pacific Terminals storage and distribution assets and the Rangeland pipeline system. We also experienced higher maintenance and power costs in the Rocky Mountains as a result of increased expenditure on flow improvers and increased volumes and natural gas prices, respectively. This was offset by lower maintenance expenses in the West Coast.

	Six Months Ended June 30, 2004	2003	Change	Percent
	(In thousands) (unaudited)			
Transition costs	$ 184	$ 397	$ (213)	(54)%

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

	Six Months Ended June 30, 2004	2003	Change	Percent
	(In thousands) (unaudited)			
General and administrative expense	$ 7,490	$ 6,984	$ 506	7%

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

	Six Months Ended June 30, 2004	2003	Change	Percent
	(In thousands) (unaudited)			
Depreciation and amortization	$ 10,955	$ 8,386	$ 2,569	31%

The increase in depreciation and amortization includes $1.7 million for depreciation on the Pacific Terminals storage and distribution system and $0.5 million for depreciation on the Rangeland pipeline system.

	Six Months Ended June 30, 2004	2003	Change	Percent
	(In thousands) (unaudited)			
Share of net income of Frontier	$ 784	$ 727	$ 57	8%

Our increased share of Frontier net income was attributable to increased volumes on Frontier pipeline, offset by increased expenses for flow improver, power and legal services.

Six Months Ended June 30, 2004	2003	Change	Percent
(In thousands) (unaudited)			

	Six Months Ended June 30,			
Interest expense	$ 8,509	$ 8,148	$ 361	4%

Interest expense increased due to an increase in borrowings incurred to partially fund the acquisition of Pacific Terminals storage and distribution system and the Rangeland pipeline system. Our weighted average borrowings during the six months ended June 2004 were $289 million compared to $225 million in the corresponding period in 2003. However, the increase in borrowings was offset by a lower weighted average interest rate of 5.7% for the first six months in 2004 compared to a weighted average interest rate of 7.2% 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.

	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003	Change	Percent
	(In thousands) (unaudited)			
Write-off of deferred financing costs and interest rate swap termination expense	$ 2,901	$	$ 2,901	

The amount relates to the write-off of deferred financing costs of $2,324 incurred in connection with the repayment of our term loan and $577 of expense incurred to terminate related interest rate swaps.

	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003	Change	Percent
	(In thousands) (unaudited)			
Income tax expense (benefit):				
Current	$ 32		$ 32	
Deferred	(46)		(46)	
	$ (14)		$ (14)	

The income taxes relate to the Canadian income of the Rangeland pipeline system acquired in May 2004.

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.

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. During the six months ended June 30, 2004, we issued 4.6 million partnership units pursuant to the registration statement. At June 30, 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

	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003	Change
		(In thousands) (unaudited)	
Net cash provided by operating activities	$ 29,872	$ 19,174	$ 10,698
Net cash used in investing activities	(146,946)	(1,144)	145,802
Net cash provided by (used in) financing activities	129,236	(19,755)	148,991

Net cash provided by operating activities

The increase in the net cash from operating activities of $10.7 million, or 56%, 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 $139.1 million related to the acquisition of the Rangeland Pipeline and MAPL Pipeline systems. Capital expenditures were $7.9 million in 2004, of which $0.7 million related to sustaining capital projects, $0.8 million related to the primarily to the transition of the Pacific Terminals storage and distribution system and our Canadian assets, and $4.6 million related to expansion. Additionally, we continue to develop the Pier 400 Project, for which, we capitalized $1.8 million for the six months ended June 30, 2004. In 2003, capital expenditures were $1.2 million, of which $0.7 million related to sustaining capital projects, $0.1 million related to transition projects, and $0.4 million related to expansion.

Net cash provided by and used in financing activities

The amount in 2004 of $129.2 million includes net proceeds of $128.6 million from our equity offerings completed in March and April, 2004, which were used principally to partly fund our Rangeland Pipeline and MAPL Pipeline acquisitions, $241.1 million net proceeds from our 7.125% unsecured senior notes offering which were used, in part, to repay our $225 million term loan, net proceeds of $11.7 million under our revolving credit facilities, and $27.1 million in distributions to the limited and general partner interests. The cash used in financing activities of $19.8 million in 2003 consisted only of distributions to the limited and general partner interests.

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 of $16.5 million in 2004, including $10 million for expansion projects, $3 million for transition capital projects and $3.5 million for sustaining capital projects.

Debt Obligations

At June 30, 2004, our debt obligations include: (i) $38.0 million on our U.S. revolving credit facility (ii) Cdn$65 million (U.S.$48.7 million) on our senior secured Canadian revolving credit facility, (iii) $245.8 million on our 7.125% senior unsecured notes, and (iv) Cdn$4.3 million (U.S.$3.2 million) payable to the seller of the MAPL assets. For further discussion of these debt obligations see "Footnote 5 Long-term Debt" to the financial statements for a complete discussion of our debt obligations.

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, crude oil price risk and currency exchange rate risk. We utilize various derivative instruments to manage our exposure to our principal market risk. Our risk management policies and procedures are designed to monitor interest rates, currency exchange rates, NYMEX and over-the-counter commodity positions, and physical volumes, grades, locations and delivery schedules to ensure that our hedging activities address our market risks.

We have interest rate swap agreements with an aggregate notional principal amount of $80.0 million to receive interest at a fixed rate of 7.125% and to pay interest at an average variable rate of six month LIBOR plus 1.6681% (set in advance or in arrears depending on the swap transaction). The interest rate swaps matures June 15, 2014 and are generally callable at the same dates and terms as the 7.125% Notes. We elected to apply hedge accounting to account for the interest rate swaps. Changes in fair values of the interest rate swaps are recorded into earnings each period. Similarly, changes in the fair value of $80 million of the Senior Notes are recorded into earnings each period. The offsetting difference of recording the change in fair value of the interest rate swaps and the change in fair value of $80 million into earnings is not expected to have a material impact on earnings as movement in fair value of the interest rate swap and the underlying debt are expected to be highly correlated.

We are subject to risks resulting from interest rate fluctuations as the interest cost on $166.7 million of our outstanding debt is based on variable rates. If the LIBOR or Canadian Bankers' Acceptance discount rates were to increase 1.0% for the remainder of 2004, our interest expense would increase $0.8 million based on the outstanding debt at June 30, 2004.

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 six months ended June 30, 2004 and 2003, "crude oil sales, net of purchases" were net of $0.5 million and $0.3 million, respectively, reflecting changes in the fair value of PMT's derivative instruments for its marketing activities. In addition, changes in the fair value of our derivative instruments related to the future sale of crude oil 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 June 30, 2004, $0.7 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 June 30, 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 June 30, 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 10 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 4.2	Indenture dated June 16, 2004, by and among Pacific Energy Partners, L.P. and Pacific Energy Finance Corporation, the guarantors, and Wells Fargo Bank, National Association, as trustee of the 7.125% Notes due 2014
*Exhibit 4.3	Registration Rights Agreement dated June 16, 2004 by and among Pacific Energy Partners, L.P. and Pacific Energy Finance Corporation, the guarantors and the Initial Purchasers of the 7.125% Notes due 2014
Exhibit 10.1	Canadian Credit Agreement dated May 11, 2004, between RPC Acquisition Company and Royal Bank of Canada and other lenders (incorporated by reference to Exhibit 10.2 to Form 8-K filed May 26, 2004)
*Exhibit 10.2	Fourth Amendment to U.S. Credit Agreement dated May 28, 2004 between Pacific Energy Group LLC and Fleet National Bank and other lenders
Exhibit 10.3	Agreement of Purchase and Sale dated June 1, 2004, by and among Imperial Oil and Rangeland Northern Pipeline Company and Pacific Energy Partners L.P. (incorporated by reference to Exhibit 10.1 to Form 8-K filed July 15, 2004)
*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 during the three months ended June 30, 2004:

Date of Event Reported	Item(s) Reported	Description
April 28, 2004	Items 7, 9 & 12*	Filed in connection with the Partnership's second quarter 2004 earnings release dated April 28, 2004.
May 11, 2004	Items 7 & 9*	Filed in connection with the Partnership's press release dated May 11, 2004 announcing the closing of the Rangeland Pipeline system acquisition.
May 11, 2004	Items 2 & 7	Filed in connection with the Partnership's closing of the acquisition of the Rangeland Pipeline system.
June 1, 2004	Items 7 & 9*	Filed in connection with Partnership's press release dated June 1, 2004 announcing its intent to offer $240 million of senior unsecured notes due 2014 in a private placement.
June 2, 2004	Items 7 & 9*	Filed in connection with the Partnership's press release dated June 2, 2004 announcing the signing of an agreement to purchase the Mid Alberta Pipeline.
June 10, 2004	Items 7 & 9*	Filed in connection with the Partnership's press release dated June 10, 2004 announcing the pricing of the private offering of $250 million principal amount of Senior Notes due 2014.
June 30, 2004	Items 7 & 9*	Filed in connection with the Partnership's press release dated June 30, 2004, announcing the closing of the Mid Alberta Pipeline acquisition.

* The information in the Forms 8-K 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

By: /s/ IRVIN TOOLE, JR.

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

August 4, 2004

By: /s/ GERALD A. TYWONIUK

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

August 4, 2004

EXHIBIT INDEX

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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.