PACIFIC ENERGY PARTNERS LP
Form 10-Q
August 08, 2003

Use these links to rapidly review the document

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, 2003

OR

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

Commission File Number 1-313345

PACIFIC ENERGY PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

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

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

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

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

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

There were 10,516,690 of the registrant's Common Units and 10,465,000 of the registrant's Subordinated Units outstanding at July 31, 2003.

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

FORM 10-Q
TABLE OF CONTENTS

PART I. FINANCIAL INFORMATION

ITEM 1. Financial Statements

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

	June 30, 2003	December 31, 2002
	(in thousands)	
	(unaudited)	

	June 30, 2003	December 31, 2002
ASSETS		
Current assets:		
Cash and cash equivalents	$ 22,148	$ 23,873
Crude oil sales receivable	34,051	24,157
Transportation accounts receivable	11,501	10,568
Crude oil inventory	2,396	3,887
Prepaid expenses	2,187	2,720
Other	446	866
Total current assets	72,729	66,071
Property and equipment, net	397,920	404,842
Investment in Frontier (note 2)	8,383	9,175
Other assets	6,570	6,950
	$ 485,602	$ 487,038
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 1,073	$ 2,752
Accrued crude oil purchases	31,835	24,385
Accrued power costs	1,178	1,706
Accrued interest payable	2,475	2,542
Due to related parties	1,228	952
Derivatives liability current portion (note 1)	5,230	4,775
Other	3,728	4,531
Total current liabilities	46,747	41,643
Long-term debt (note 4)	225,000	225,000
Derivatives liability (note 1)	7,133	2,600
Other liabilities	2,600	2,600
Total liabilities	281,480	271,843
Commitments and contingencies (note 6)		
Partners' Capital:		
Common unitholders (10,465,000 units outstanding at June 30, 2003 and December 31, 2002)	159,252	163,172
Subordinated unitholders (10,465,000 units outstanding at June 30, 2003 and December 31, 2002)	53,148	57,069
General Partner interest	2,169	2,329
Undistributed employee long-term incentive compensation (note1)	1,916	
Accumulated other comprehensive loss (note 1)	(12,363)	(7,375)
Net partners' capital	204,122	215,195
	$ 485,602	$ 487,038

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. (Note 1)
Successor to Pacific Energy (Predecessor)
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	For the Three Months Ended		For the Six Months Ended	
	June 30, 2003	June 30, 2002	June 30, 2003	June 30, 2002
	(in thousands) (unaudited)			
Pipeline transportation revenue	$ 25,644	$ 27,740	$ 50,935	$ 48,809
Crude oil sales, net of purchases of $87,935 and $79,903 for the three months ended June 30, 2003 and 2002 and $174,557 and $139,832 for the six months ended June 30, 2003 and 2002	5,093	5,846	10,752	11,372
Net revenues before operating expenses	30,737	33,586	61,687	60,181
Expenses:				
Operating	14,344	15,069	26,992	26,275
Transition costs		1,144	397	1,976
General and administrative	3,002	1,543	6,984	2,885
Depreciation and amortization	4,205	4,317	8,386	7,404
	21,551	22,073	42,759	38,540
Share of net income of Frontier	386	227	727	495
Operating income	9,572	11,740	19,655	22,136
Other income	110	166	145	283
Interest income	46	64	102	249
Interest expense	(4,102)	(2,338)	(8,148)	(3,855)
Net income	$ 5,626	$ 9,632	$ 11,754	$ 18,813
Net income for the general partner interest for the three and six months ended June 30, 2003	$ 112		$ 235	
Net income for the limited partner interests for the three and six months ended June 30, 2003	$ 5,514		$ 11,519	
Basic and diluted net income per limited partner unit	$ 0.26		$ 0.55	
Weighted average limited partner units outstanding for the three and six months ended June 30, 2003:				
Basic	20,930		20,930	
Diluted	21,086		21,065	

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. (Note 1)
Successor to Pacific Energy (Predecessor)
CONDENSED CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL

	Limited Partner Units		Limited Partner Amounts					
	Common	Subordinated	Common	Subordinated	General Partner Interest	Undistributed Employee Long-Term Incentive Compensation	Accumulated Other Comprehensive Loss	Total
					(in thousands) (unaudited)			
Balance, December 31, 2002	10,465	10,465	$ 163,172	$ 57,069	$ 2,329	$	$ (7,375)	$ 215,195
Distribution to limited partners			(9,680)	(9,680)				(19,360)
Distribution to general partner					(395)			(395)
Net income			5,760	5,759	235			11,754
Undistributed employee compensation under long-term incentive plan (note 1)						1,916		1,916
Change in fair value of interest rate hedging derivatives (note 1)							(4,988)	(4,988)
Balance, June 30, 2003	10,465	10,465	$ 159,252	$ 53,148	$ 2,169	$ 1,916	$ (12,363)	$ 204,122

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. (Note 1)
Successor to Pacific Energy (Predecessor)
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	For the Three Months Ended		For the Six Months Ended	
	June 30, 2003	June 30, 2002	June 30, 2003	June 30, 2002
		(in thousands) (unaudited)		
Net income	$ 5,626	$ 9,632	$ 11,754	$ 18,813
Change in fair value of interest rate hedging derivatives (note 1)	(4,127)		(4,988)	
Comprehensive income	$ 1,499	$ 9,632	$ 6,766	$ 18,813

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. (Note 1)
Successor to Pacific Energy (Predecessor)
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Six Months Ended	
	June 30, 2003	**June 30, 2002**
	(in thousands) (unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 11,754	$ 18,813
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	8,386	7,404
Amortization of debt issue costs	557	217
Non-cash employee compensation under the long-term incentive plan	1,843	
Share of net income of Frontier	(727)	(495)
	21,813	25,939
Net changes in operating assets and liabilities:		
Accounts receivable	(10,827)	(11,664)
Due to related party	276	885
Crude oil inventory	1,491	(46)
Prepaid expenses	533	356
Other current and non-current assets	109	(3,724)
Accounts payable	(1,679)	1,459
Accrued expenses	6,855	3,490
Provision for loss on rate case litigation		(1,500)
Distributions (to) from Frontier, net	1,333	577
Other current and non-current liabilities	(730)	(276)
	(2,639)	(10,443)
NET CASH PROVIDED BY OPERATING ACTIVITIES	19,174	15,496
CASH FLOWS FROM INVESTING ACTIVITIES		
Acquisition of pipeline assets		(95,196)
Additions to property and equipment	(1,191)	(2,416)
Disposal of equipment	47	
NET CASH USED IN INVESTING ACTIVITIES	(1,144)	(97,612)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from note payable to bank		87,000
Related party note payable		(122)
Capital contributions of members (pre initial public offering)		8,770
Distributions to members (pre initial public offering)		(6,000)
Distributions to limited partners (post initial public offering)	(19,360)	

	For the Six Months Ended	
Distributions to general partner (post initial public offering)	(395)	
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	(19,755)	89,648
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(1,725)	7,532
CASH AND CASH EQUIVALENTS, beginning of reporting period	23,873	9,511
CASH AND CASH EQUIVALENTS, end of reporting period	$ 22,148	$ 17,043
Supplemental disclosures		
Cash paid for interest	$ 7,536	$ 3,409
Noncash financing activities change in fair value of interest rate hedging derivatives	$ 4,988	$

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P.
Successor to Pacific Energy (Predecessor)
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
June 30, 2003
(Unaudited)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

On July 26, 2002, Pacific Energy Partners, L.P. (the "Partnership") completed an initial public offering of 8,600,000 common units representing limited partner interests in the Partnership for net proceeds of $151.3 million. Accordingly, net income per limited partner unit for the three and six months ended June 30, 2002 in the accompanying condensed consolidated income statement is not applicable. The Partnership, which was formed by The Anschutz Corporation ("Anschutz") in February 2002, and its subsidiaries are engaged in gathering, blending, transporting, storing, marketing, and distributing crude oil.

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

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

The unaudited condensed consolidated financial statements do not reflect the ownership or results of operations of the black oil storage and pipeline distribution assets of Edison Pipeline and Terminal Company, which assets were acquired by Pacific Terminals LLC, a wholly-owned indirect subsidiary of the Partnership ("Pacific Terminals"), as the acquisition was completed subsequent to June 30, 2003 (see Note 7, Subsequent Events).

The unaudited condensed consolidated financial statements present the Partnership as a single entity, separate from Anschutz, during the periods presented. The 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 by accounting principles 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, 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, 2003 is derived from the Partnership's unaudited consolidated financial statements. The financial data as of December 31, 2002 is derived from the Partnership's audited consolidated financial statements. The financial data for the three and six months ended June 30, 2002 is derived from the unaudited combined financial statements of Pacific Energy (Predecessor).

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, 2002.

Description of Business and History

PEG was formed in August 2001, and at June 30, 2003 and December 31, 2002, owned 100% of PPS, PMT, RMP, AREPI and RPL.

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

Effective May 1, 1999, ARCO Midcon, formerly ARCO Pipe Line Company ("ARCO"), exchanged its Line 63 assets for a 26.5% ownership interest in PPS and a note of $63.6 million. On June 7, 2001, ARCO made a capital contribution of $63.6 million to PPS, and PPS Holding Company ("Holdings"), a wholly owned subsidiary of Anschutz and the 100% owner of the General Partner, then purchased ARCO's ownership interest in PPS for $47.0 million in cash, and PPS repaid the $63.6 million note. This purchase of an additional ownership interest in PPS resulted in negative goodwill of $40.6 million, which was allocated proportionately to reduce property, plant and equipment of PPS.

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

PMT was formed in June 2001, in connection with the purchase of certain assets in the San Joaquin Valley for approximately $14.4 million. The assets acquired consist of 122 miles of intrastate crude oil gathering pipelines and six storage and blending facilities with approximately 254,000 barrels of storage capacity and blending capacity of up to 65,000 barrels per day as well as a base stock of crude oil. The purchase price was allocated among the fair values of the assets acquired and no goodwill resulted from this acquisition. The purchase price is subject to adjustment based on operating cash flows (as defined in the purchase agreement) during the 24 months following the acquisition. Depending on the amount of this cash flow, the purchase price could decrease by up to $1.5 million or increase by up to $7.5 million. However, the seller remains liable for various indemnity, product supply and construction obligations undertaken in connection with the sale. PMT and the seller are engaged in discussions relating to the settlement of all obligations undertaken by them in connection with PMT's purchase of these assets.

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

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

RPL, which was transferred to PEG on March 1, 2002 in preparation for the Partnership's initial public offering, owns a 22.22% partnership interest in Frontier, a Wyoming general partnership, which owns Frontier pipeline. RPL owned a 12.5% partnership interest in Frontier until December 2001, at which time it acquired an additional 9.72% partnership interest from an affiliate of BP plc for $8.6 million. Frontier pipeline is a 290-mile pipeline with a throughput capacity of 62,200 barrels per day that originates in Casper, Wyoming and delivers crude oil to the AREPI pipeline and the Salt Lake City Core system.

Pacific Terminals was transferred by Holdings to PEG on July 21, 2003, pursuant to an agreement that was entered into in connection with the Partnership's initial public offering. Pacific Terminals owns the Pacific Terminals storage and distribution system which is comprised of certain of the assets of Edison Pipeline and Terminal Company, a division of Southern California Edison Company, which were purchased by Pacific Terminals on July 31, 2003. The financial statements included herein do not reflect the ownership or results of operations of the assets comprising the Pacific Terminals storage and distribution system as these assets were acquired subsequent to June 30, 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, and contingent liabilities.

Environmental Remediation

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

Revenue Recognition

The California Public Utilities Commission ("CPUC") economically regulates PPS's common carrier crude oil pipeline operations. All shipments on the regulated pipelines are governed by tariffs authorized and approved by the CPUC, and revenue is recognized when the transported crude oil volumes are delivered to a tariff destination point. Tariffs on Line 2000 are market-based, established based on market considerations subject to certain contractual restraints. Tariffs on Line 63 are cost-of-service based, developed based on the various costs to operate and maintain the pipeline as well as a charge for depreciation of the capital investment in the pipeline and an authorized rate of return.

AREPI and Frontier pipelines are common carrier pipelines under the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). AREPI and Frontier pipelines transport crude oil under various cost-based tariff agreements at published rates, depending on the type and quality of the crude oil. The Western Corridor system and Salt Lake City Core system are common carrier pipelines under the jurisdiction of both the FERC and the Wyoming Public Service Commission.

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

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

Transition Costs

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

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 inventory of crude oil. The Partnership does not engage in speculative derivative activities of any kind. Derivative instruments are included in other assets in the accompanying condensed consolidated balance sheets. Changes in the fair value of the Partnership's derivatives related to crude oil inventory are recognized in net income. For the three and six months ended June 30, 2003, "crude oil sales, net of purchases" are net of $0.1 million and $0.3 million, respectively, related to changes in fair value of PMT's derivative instruments for its marketing activities.

In August and September 2002, PEG entered into three interest rate swap agreements pursuant to which it executed five interest rate swap transactions that mature in 2009, totaling $140.0 million, and two interest rate swap transactions that mature in 2007, totaling $30.0 million. The Partnership designated these swaps as a hedge of its exposure to variability in future cash flows attributable to the LIBOR interest payments due on $170.0 million outstanding under PEG's term loan facility. The average swap rate on this $170.0 million of debt is approximately 4.25%, resulting in an all-in interest rate on the $170.0 million of debt of approximately 7.00% (including the current applicable margin of 2.75%).

As a result of the purchase of the assets that comprise the Pacific Terminals storage and distribution system on July 31, 2003, the applicable margin increased by a margin of 0.50% and will remain at that level until April 26, 2004, or until the Partnership successfully concludes an equity offering that reduces certain ratios to specified levels, whichever is earlier. The 2.75% applicable margin rate referenced in the preceding paragraph does not include this increase.

As of June 30, 2003, interest rates, as measured by market quotations for the future periods covered by the interest rate swap agreements, had declined as compared to August and September 2002, when PEG entered into these interest rate swap agreements. This decline resulted in

an unrealized loss of $12.4 million on the aggregate interest rate hedge, which is recorded as a liability at June 30, 2003. The $12.4 million liability is shown on the condensed consolidated balance sheet in two components, a current liability of $5.2 million, and a long term liability of $7.2 million. The unrealized loss reflecting the decline in interest rates from December 31, 2002, is shown in "other comprehensive income," a component of partners' capital, and not in the condensed consolidated income statement. Should interest rates remain unchanged from the June 30, 2003 market quotations for these future periods, actual losses realized on the interest rate swap agreements in each of the future periods would be offset by the benefit of lower floating rates in those periods, such that total net interest expense on the $170.0 million of hedged debt would be fixed at the all-in interest rate of approximately 7.00%, plus the 0.50% increase resulting from the Pacific Terminals acquisition, as described in the preceding paragraph.

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

Credit risk is the failure of the derivative agreement counterparty to perform under the terms of the agreement. When the fair value of a derivative agreement is positive, the counterparty owes the Partnership, which creates credit risk for the Partnership. When the fair value of a derivative agreement is negative, the Partnership owes the counterparty and, therefore, it does not possess credit risk. As of June 30, 2003, the counterparties to the interest rate swap agreements did not represent a credit risk to the Partnership as the fair value of each derivative agreement was negative.

Impairment of Long-Lived Assets

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

Income Taxes

No provision for federal or state income taxes related to operations is included in the accompanying condensed consolidated financial statements. The Partnership is not a taxable entity and is not subject to federal or state income taxes as the tax effect of operations is accrued to its unitholders. Net income for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under the Partnership's First Amended and Restated Agreement of Limited Partnership. Individual unitholders have different investment bases depending upon the timing and price of acquisition of partnership units. Further, each unitholder's tax accounting, which is partially dependent upon the unitholder's tax position differs from the accounting followed in the consolidated financial statements. Accordingly, the aggregate difference in the basis of the Partnership's net assets for financial and tax reporting purposes cannot be readily determined because information regarding each unitholder's tax attributes in the Partnership is not available to the Partnership.

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

Net Income per Unit

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

Diluted net income per limited partner unit is calculated in the same manner as basic net income per limited partner unit above, except that the weighted average number of outstanding limited partner units is increased to include the dilutive effect of outstanding options and restricted units by application of the treasury stock method pursuant to Statement of Financial Accounting Standards No. 128, "Earnings per Share." For the three and six months ended June 30, 2003, the denominator of diluted net income per limited partner unit was increased by 155,687 units and 135,108 units respectively, as compared to the denominator of basic net income per limited partner unit.

Restricted Units and Unit Options

As permitted under Statement of Financial Accounting Standards No. 123 ("SFAS No. 123"), "Accounting for Stock-Based Compensation," the Partnership has elected to measure costs for restricted units and unit options using the intrinsic value method, as prescribed by Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees." Compensation expense related to the restricted units is recognized by the Partnership over the vesting periods of the units. Accordingly, the compensation expense related to the restricted units that is allocable to the current reporting period has been recognized in the accompanying condensed consolidated statements of income, and non-cash employee compensation related to the long-term incentive plan is included in "undistributed employee long-term incentive compensation" in the accompanying condensed consolidated balance sheets. No compensation expense related to the unit options has been recognized in the accompanying condensed consolidated financial statements. Had the Partnership determined compensation cost based on the fair value at the grant date for its unit options under SFAS 123, net income and earnings per limited partner unit would not have been materially reduced for the three and six months ended June 30, 2003.

Reclassifications

Certain prior year balances in the accompanying condensed consolidated financial statements have been reclassified to reflect changes in the classification of certain expenses as operating or general and administrative due to the nature of such expenses. In addition, certain costs associated with crude oil purchases have been reclassified from operating expense to crude oil sales, net of purchases due to the nature of such costs. These reclassifications of prior year expenses conform to current year presentation.

Accounting Pronouncements

In May 2003, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 150 ("SFAS No. 150"), "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity." This statement establishes standards for the measurement and classification of certain financial instruments with characteristics of both liabilities and equity. SFAS No. 150 is effective for financial instruments entered into or modified after May 31, 2003, and otherwise effective the first interim period beginning after June 15, 2003. The adoption of this standard did not have any impact on the Partnership's financial position or results of operations.

In April 2003, the FASB issued Statement of Financial Accounting Standards No. 149 ("SFAS No. 149"), "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." This statement amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities under Statement of Financial Accounting Standards No. 133 ("SFAS No. 133"), "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003 and should be applied prospectively. However, provisions related to SFAS No. 133 Implementation Issues effective for fiscal quarters beginning prior to June 15, 2003 should continue to be applied in accordance with their respective dates. The adoption of this standard is not expected to have any impact on the Partnership's financial position or results of operations.

2. INVESTMENT IN FRONTIER PIPELINE COMPANY

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

The summarized balance sheets of Frontier at June 30, 2003 and December 31, 2002 and the statements of income for the three and six months ended June 30, 2003 and 2002 are presented below:

Balance Sheets

	June 30, 2003	December 31, 2002
	(in thousands) (unaudited)	
Current assets	$ 1,949	$ 4,481
Property and equipment, net	9,083	9,252
Other assets	1	1
	$ 11,033	$ 13,734
Current liabilities	$ 460	$ 365
Other liabilities	2,229	2,298
Partners' capital	8,344	11,071
	$ 11,033	$ 13,734

Statements of Income

	For the Three Months Ended		For the Six Months Ended	
	June 30, 2003	June 30, 2002	June 30, 2003	June 30, 2002
	(in thousands) (unaudited)			
Revenue	$ 2,408	$ 2,521	$ 4,538	$ 5,971
Operating expense	(585)	(1,431)	(1,092)	(2,004)
Depreciation expense	(91)	(82)	(181)	(165)
Operating income	1,732	1,008	3,265	3,802
Rate case litigation settlement				(1,600)
Other income	3	10	6	21
Net income	$ 1,735	$ 1,018	$ 3,271	$ 2,223

3. RELATED PARTY TRANSACTIONS

During the six months ended June 30, 2003, the Partnership paid distributions to Anschutz of $11.8 million in respect of the fourth quarter 2002 and the first quarter 2003 on its common units, subordinated units and 2% general partner interest. During the six months ended June 30, 2002, the Predecessor paid a distribution to Anschutz of $6.0 million.

A subsidiary of Anschutz was a shipper on Line 2000 and was charged the published tariff rates applicable to "participating shippers" until March 31, 2003, when an agreement between the Anschutz subsidiary and a third party, the performance of which required the Anschutz subsidiary to ship on Line 2000, was assigned to PMT. The Partnership charged this subsidiary approximately $0.4 million and $1.6 million for the six months ended June 30, 2003 and 2002, respectively. The amount charged to Anschutz for these shipments in 2003 was paid prior to June 30, 2003. As an original sponsor of the Line 2000 project, Anschutz and its affiliates qualify for participating shipper tariff rates on Line 2000.

An affiliate of Anschutz is a shipper on AREPI pipeline and is charged published tariff rates. The Partnership charged this affiliate transportation fees of $0.1 million during each of the six month periods ended June 30, 2003 and June 30, 2002. The amount associated with these shipments included in accounts receivable was $0.1 million at June 30, 2003. An affiliate of Anschutz is a shipper on an RMP pipeline and is charged published tariff rates. The Partnership charged this affiliate transportation fees of $0.1 million during each of the six month periods ended June 30, 2003 and June 30, 2002. The amount associated with these shipments included in accounts receivable was $0.1 million at June 30, 2003. In addition, beginning in 2003, RMP's trucking operation began hauling water for an Anschutz oil and gas subsidiary at rates equivalent to those charged to third parties. The Partnership charged this affiliate hauling fees of $0.2 million during the six months ended June 30, 2003. The amount associated with fees included in accounts receivable was $0.1 million at June 30, 2003.

Prior to April 1, 2002, Anschutz employed various personnel who worked directly on AREPI pipeline and provided other executive, accounting and administrative support to AREPI. Most of these individuals continue to provide services to AREPI pipeline, but are now employed by the General Partner. During the six months ended June 30, 2002, Anschutz charged AREPI approximately $0.3 million for salaries of the pipeline related personnel and for various support services. No amounts were charged by Anschutz to AREPI in 2003.

RMP serves as the contract operator for Anschutz Wahsatch Gathering System, Inc. ("AWGS"), a wholly owned subsidiary of Anschutz that owns a natural gas gathering system in Wyoming and Utah. AWGS reimburses RMP for the direct costs of operating the AWGS assets, such as the salary and benefit costs incurred by the direct assigned field operating and maintenance personnel related to AWGS operations. In addition, AWGS pays an annual management fee of $0.3 million to reimburse RMP for the portion of time spent by management and for other overhead services related to AWGS activities. For the six months ended June 30, 2003 and 2002, amounts charged to AWGS represented one-half of the annual management fee. The management fee charged for the quarter ended June 30, 2003 was included in the accounts receivable of RMP at June 30, 2003.

During 2002, Anschutz paid certain expenses on behalf of RMP. Amounts charged during 2002 for reimbursement were $0.3 million, which is included in "due to related parties" of RMP at June 30, 2003. In 2002, Anschutz also paid certain expenses on behalf of RPL. Amounts charged during 2002 for reimbursement were $0.4 million, which is included in "due to related parties" of RPL at June 30, 2003.

The Partnership does not have any employees. The General Partner, which is a wholly owned indirect subsidiary of Anschutz, employed approximately 220 individuals at June 30, 2003 who directly supported the operations of the Partnership. All expenses incurred by the General Partner are charged

to the Partnership. At June 30, 2003, amounts due to the General Partner for reimbursement of payroll and related costs amounted to $0.6 million which is included in "due to related parties".

In 2002, the Partnership began utilizing the financial accounting system owned and provided by Anschutz under a shared services arrangement. In addition, the Partnership utilizes the services of Anschutz's risk management personnel for assistance in acquiring the Partnership's insurance, and the Partnership's surety bonds are issued under Anschutz's bonding line. Out-of-pocket costs incurred by Anschutz for the benefit of the Partnership for computer consultants, insurance premiums and surety bond costs were reimbursed by the Partnership. In January 2003, Anschutz 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. Amounts accrued for the six months ended June 30, 2003 represent one-half of the annual fee charged by Anschutz and were included in "other" liabilities at June 30, 2003.

In 2002, Anschutz provided office space to several employees of the General Partner at no cost to the Partnership. Beginning in January 2003, the Partnership leased approximately 4,700 square feet of office space from an affiliate of Anschutz, for a term of five years at an initial annual cost of $0.1 million, the prevailing market rate for comparable space. Amounts charged by an affiliate of Anschutz for the six months ended June 30, 2003 were paid prior to quarter end.

4. LONG-TERM DEBT

The Partnership's long-term debt obligations at June 30, 2003 and December 31, 2002 are shown below:

	June 30, 2003	December 31, 2002
	(in thousands)	
	(unaudited)	
Senior secured revolving credit facility	$	$
Senior secured term loan facility	225,000	225,000
Total	225,000	225,000
Less current portion		
Long-term debt	$ 225,000	$ 225,000

A $200.0 million revolving credit facility is available for general partnership purposes, including working capital, letters of credit and distributions to unitholders and to finance future acquisitions, including the acquisition of the black oil storage and pipeline distribution assets of Edison Pipeline and Terminal Company by Pacific Terminals (see Note 7, Subsequent Events). The revolving credit facility has a borrowing sublimit of $45.0 million for working capital, letters of credit and partnership distributions to unitholders.

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

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

Indebtedness under the revolving credit facility and the term loan facility bear interest at PEG's option, at either (i) the base rate, which is equal to the higher of the prime rate as announced by Fleet National Bank or the Federal Funds rate plus 0.50% (each plus an applicable margin ranging from 0%

to 0.50% for the revolving credit facility and ranging from 0.50% to 0.75% for the term loan facility) or (ii) LIBOR plus an applicable margin ranging from 1.25% to 2.50% for the revolving credit facility and ranging from 2.50% to 2.75% for the term loan facility. The applicable margins are subject to change based on the credit rating of the facilities or, if they are not rated, the credit rating of PEG. As a result of the purchase of the assets that comprise the Pacific Terminals storage and distribution system on July 31, 2003, the applicable margin will be increased by an additional 0.50% until April 26, 2004, or until the Partnership successfully concludes an equity offering that reduces certain ratios to specified levels, whichever is earlier.

PEG incurs a commitment fee which ranges from 0.25% to 0.50% per annum on the unused portion of the revolving credit facility. Under the credit agreement, PEG is prohibited from declaring dividends or distributions if any event of default, as defined in the credit agreement, occurs or would result from such declaration. In addition, the credit agreement contains certain financial covenants and covenants limiting the ability of PEG and certain of its subsidiaries to, among other things, incur or guarantee indebtedness, change ownership or structure, including consolidations, liquidations and dissolutions and enter into a new line of business. At June 30, 2003, PEG and its subsidiaries that are guarantors under the credit agreement were in compliance with all such covenants.

At June 30, 2003, the Partnership had letters of credit outstanding totaling $10.3 million for PMT activities, which were issued under PEG's $200.0 million revolving credit facility. On July 31, 2003, $149.0 million was drawn on the revolving credit facility to fund, in part, the acquisition of the assets comprising the Pacific Terminals storage and distribution system (see Note 7, Subsequent Events). As a result of the July 31, 2003 draw on the revolving credit facility, the remaining available balance was reduced to $36.6 million.

5. 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 and PMT and will in the future include Pacific Terminals (see Note 7, Subsequent Events). Rocky Mountain operations include RMP, AREPI and RPL. The reporting units comprising each segment have been aggregated to reflect how the assets are operated and managed. General and administrative costs, which consist of executive management, accounting and finance, human resources, information

technology, investor relations, legal, and marketing and business development, are not allocated to the individual segments. Information regarding these two operating units is summarized below:

	For the Three Months Ended,		For the Six Months Ended,	
	June 30, 2003	June 30, 2002	June 30, 2003	June 30, 2002
	(in thousands) (unaudited)			
Segment Operating Income				
West Coast Operations:				
Pipeline transportation revenue:				
Unaffiliated customers	$ 15,323	$ 16,201	$ 30,768	$ 31,367
Affiliates		857	447	1,671
Total pipeline transportation revenue	15,323	17,058	31,215	33,038
Crude oil sales, net of purchases(1)	5,093	5,846	10,752	11,372
Net revenue before operating expenses	20,416	22,904	41,967	44,410
Expenses:				
Operating	8,260	9,512	16,266	18,919
Transition costs		50		116
Depreciation and amortization	2,859	2,794	5,681	5,493
Total expenses	11,119	12,356	21,947	24,528
Operating income(2)	$ 9,297	$ 10,548	$ 20,020	$ 19,882
Capital expenditures	$ 347	$ 1,168	$ 717	$ 1,539

	For the Three Months Ended,		For the Six Months Ended,	
Identifiable assets	$ 346,081	$ 355,989	$ 346,081	$ 355,989
Rocky Mountain Operations:				
Pipeline transportation revenue:				
Unaffiliated customers	$ 10,077	$ 10,638	$ 19,476	$ 15,602
Affiliates	244	44	244	169
Total pipeline transportation revenue	10,321	10,682	19,720	15,771
Expenses:				
Operating	6,084	5,557	10,726	7,356
Transition costs		1,094	397	1,860
Depreciation and amortization	1,346	1,523	2,705	1,911
Total expenses	7,430	8,174	13,828	11,127
Share of net income of Frontier	386	227	727	495
Operating income(2)	$ 3,277	$ 2,735	$ 6,619	$ 5,139
Capital expenditures	$ 284	$ 734	$ 474	$ 877
Identifiable assets	$ 139,521	$ 128,601	$ 139,521	$ 128,601

(1)

The above amounts are net of purchases of $87,935 and $79,903 for the three months ended June 30, 2003 and 2002, respectively. The above amounts are net of purchases of $174,557 and $139,832 for the six months ended June 30, 2003 and 2002, respectively.

15

(2)

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

	For the Three Months Ended		For the Six Months Ended	
	June 30, 2003	**June 30, 2002**	**June 30, 2003**	**June 30, 2002**
		(in thousands) (unaudited)		
Income Statement Reconciliation				
Operating income from above:				
West Coast Operations	$ 9,297	$ 10,548	$ 20,020	$ 19,882
Rocky Mountain Operations	3,277	2,735	6,619	5,139
Total operating income from above	12,574	13,283	26,639	25,021
Less: General and administrative	3,002	1,543	6,984	2,885

	For the Three Months Ended		For the Six Months Ended	
Operating income	9,572	11,740	19,655	22,136
Other income	110	166	145	283
Interest income	46	64	102	249
Interest expense	(4,102)	(2,338)	(8,148)	(3,855)
Net income	$ 5,626	$ 9,632	$ 11,754	$ 18,813

6. COMMITMENTS AND CONTINGENCIES

On March 15, 2002, Sinclair Oil Corporation ("Sinclair") filed a complaint with the Wyoming Public Service Commission ("WPSC") alleging that RMP's common stream rules and specifications and RMP's refusal to prohibit certain types of crude oil diluents from the common stream, all in respect of the Big Horn segment of the Western Corridor system, are adverse to Sinclair and the public interest. On April 21, 2003, the WPSC deliberated Sinclair's complaint and verbally announced that RMP will be required to adopt tariff language that prohibits certain types of crude oil diluents from the common stream or, in the alternative, that shippers who receive crude oil from the common stream that includes diluents be compensated for any disadvantage they suffer from the effects of the diluents. Until a written order is issued by the WPSC, which is expected in August 2003, the Partnership cannot predict with any degree of certainty the effect of the WPSC's April 21, 2003 decision on the Partnership's operations. However, this ruling is not expected to have a material adverse effect on the Partnership's financial position, results of operations or liquidity.

On April 15, 2002, Sinclair filed a complaint with the FERC challenging RMP's $1.32 per barrel rate for shipments from the Canadian border to Casper, Wyoming. RMP answered the complaint with a general denial of Sinclair's allegations. In June 2003 the dispute with Sinclair was fully settled by the execution of an agreement between Sinclair and RMP pursuant to which RMP has adopted a new Canadian border to Casper tariff that provides a range of volume incentive rates that decrease as pipeline volumes increase, with the highest rate in the range remaining at the previous rate of $1.32 per barrel, and the lowest rate being $1.10 per barrel. RMP expects the new incentive rate structure, which was implemented effective July 1, 2003, to result in increased volume and revenue, thereby benefiting the Partnership.

On July 22, 2002, RMP filed an application with the FERC seeking authority to charge market-based rates on its Western Corridor system. Protests to the application for market-based rates were filed by Sinclair, Tesoro Refining and Marketing Company, ConocoPhillips and Chevron Products Company. As part of the settlement with Sinclair described in the previous paragraph, RMP agreed to withdraw its market-based rate application and not re-file it for a period of two years, subject to certain

exceptions. While being granted the right to set tariff rates on the basis of market considerations, rather than cost of service, would give RMP greater convenience and a desirable degree of pricing flexibility and responsiveness, RMP's withdrawal of its application for such authority, and its inability to re-file a similar application for two years, are not expected to have a material adverse effect on the Partnership's financial position, results of operations or liquidity.

The Partnership is subject to numerous federal, state and local laws which regulate the discharge of materials into the environment or that otherwise relate to the protection of the environment. The Partnership currently has an environmental remediation liability resulting from the acquisition of ARCO's interest in PPS in 2001. The accrued liability was $2.6 million at June 30, 2003 and was classified in the condensed consolidated balance sheets within "other liabilities." This does not include any of the liabilities associated with the assets comprising the Pacific Terminals storage and distribution system, as they were purchased after June 30, 2003. 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 parties.

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

7. SUBSEQUENT EVENT

(a) On July 31, 2003, Pacific Terminals LLC completed the acquisition of the black oil storage and pipeline distribution assets of Edison Pipeline and Terminal Company, a division of Southern California Edison Company, for a purchase price of $158.2 million plus adjustments for certain pre-closing capital expenditures and other costs and the closing date value of displacement oil and warehouse inventory. It is estimated that the adjustments will total $9 million, $1.1 million of which was paid in conjunction with the July 31, 2003 closing, and the remainder of which is expected to be paid in the third quarter of 2003 after the adjustments are finalized. In addition, an estimated $3 million of transaction costs and liabilities have or will be paid or assumed by Pacific Terminals in connection with the acquisition. These assets, which comprise the Pacific Terminals storage and distribution system, include tanks having 9.4 million barrels of storage capacity, of which approximately 6.7 million barrels are in active commercial service. The Pacific Terminals storage and distribution system will be used by the Partnership to satisfy the black oil storage and distribution needs of the refining, pipeline, and marine terminal industries in the Los Angeles Basin. At the closing on July 31, 2003, $159.3 million of the purchase price was paid with proceeds of $149.0 million from borrowings under the Partnership's $200 million revolving credit facility and $10.3 million from cash on hand. The Partnership anticipates repayment of a portion of the $149.0 million of borrowings under the revolving credit facility with proceeds from the issuance of additional common units.

The acquisition will be accounted for by the purchase method of accounting pursuant to Statement of Financial Accounting Standards No. 141, "Business Combinations." 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. However, based upon preliminary estimates, approximately 40% of the purchase price will be allocated to land, with the balance being allocated to depreciable tanks, pipelines and equipment.

(b) On July 18, 2003, the Partnership declared a cash distribution of $0.4625 per limited partner unit, payable on August 14, 2003 to unitholders of record as of July 31, 2003.

(c) On August 1, 2003, the Partnership filed a universal shelf registration statement on Form S-3 to register $550.0 million of equity securities and debt securities for issuance from time to time and in such amounts as is determined by market conditions and the needs of the Partnership. The registration statement also covers, for possible future sales, up to 1,865,000 common units held by the General Partner, which acquired these common units as partial consideration for its contribution to the Partnership of assets and liabilities in connection with the Partnership's initial public offering.

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

We caution you that the forward-looking statements in this 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, blending, transporting, storing, marketing and distributing crude oil. For a more detailed description of these and other factors that may affect the forward-looking statements, please read "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations Risk Factors" contained in our annual report on Form 10-K for the year ended December 31, 2002. The risk factors could cause our actual results to differ materially from those contained in any forward-looking statement. You should not put undue reliance on these statements. We disclaim any obligation to announce publicly the result of any revision to any of the forward-looking statements to reflect future events or developments.

Introduction

The following discussion of the financial condition and results of operations of Pacific Energy Partners, L.P., the successor to Pacific Energy (Predecessor) (as defined below) should be read together with the condensed consolidated financial statements and the notes thereto set forth elsewhere in this report. The discussion set forth in this section pertains to the unaudited condensed consolidated balance sheet, statements of income and statements of cash flows of, as well as equity investment in, the Partnership and its 100% ownership interest in Pacific Energy Group LLC ("PEG"), whose subsidiaries consist of: (i) Pacific Pipeline System LLC ("PPS"), owner of Line 2000 and the Line 63 system, (ii) Pacific Marketing and Transportation LLC ("PMT"), owner of the PMT gathering and blending assets, (iii) Rocky Mountain Pipeline System LLC ("RMP"), owner of the Western Corridor system and the Salt Lake City Core system assets purchased on March 1, 2002, (iv) Anschutz Ranch East Pipeline LLC ("AREPI"), owner of AREPI pipeline, and (v) Ranch Pipeline LLC ("RPL"), the owner of a 22.22% partnership interest in Frontier Pipeline Company ("Frontier"). The financial data and results of operations for PPS, PMT, RMP, AREPI and RPL for the three and six months ended June 30, 2002, are presented on a combined basis and constitute "Pacific Energy (Predecessor)" or the "Predecessor". As a result of the initial public offering on July 26, 2002, the financial data and results of operations of PPS, PMT, RMP, AREPI and RPL for the three and six months ended June 30, 2003, are presented on a consolidated basis as successor to the Predecessor.

On July 31, 2003, Pacific Terminals LLC, a wholly-owned indirect subsidiary of the Partnership ("Pacific Terminals") completed the acquisition of the black oil storage and pipeline distribution assets of Edison Pipeline and Terminal Company, a division of Southern California Edison Company. These assets comprise the Pacific Terminals storage and distribution system. The financial data included herein does not reflect the ownership or results of operations of the assets comprising the Pacific Terminals storage and distribution system as these assets were acquired subsequent to June 30, 2003.

Critical Accounting Policies

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 condensed consolidated financial statements), the following may involve a higher degree of judgment and complexity:

We routinely apply the provisions of purchase accounting when recording our acquisitions. Application of purchase accounting requires that we estimate the fair value of the individual assets acquired. The valuation of the fair value of the assets involves a number of judgments and estimates.

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

We accrue an estimate of the undiscounted costs of environmental remediation for work at identified sites where an assessment has indicated that cleanup costs are probable and may be reasonably estimated. In making these estimates, we consider information that is currently available, existing technology, enacted laws and regulations, and our estimates of the timing of the required remedial actions.

Overview

We are a Delaware limited partnership formed in February 2002. On July 26, 2002, we completed an initial public offering of common limited partner units for net proceeds of $151.3 million.

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

We generate revenue primarily by charging tariff rates for transporting crude oil on our pipelines. The amount of revenue we generate depends on the level of these tariff rates and the amount of

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

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

The tariff rates charged on AREPI pipeline and Frontier pipeline are regulated by the Federal Energy Regulatory Commission ("FERC") under a cost-based rate methodology. The FERC and the Wyoming Public Service Commission regulate tariffs on the Western Corridor and Salt Lake City Core systems on a cost-based methodology.

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

This report on Form 10-Q should be read in conjunction with the Partnership's annual report on Form 10-K for the year ended December 31, 2002.

Results of Operations

The table below sets forth certain unaudited segment operating results by regional operating unit for the three and six months ended June 30, 2003 and 2002:

	For the Three Months Ended,		For the Six Months Ended,	
	June 30, 2003	June 30, 2002	June 30, 2003	June 30, 2002
	(in thousands) (unaudited)			

	For the Three Months Ended,		For the Six Months Ended,	
Segment Operating Income				
West Coast Operations:				
Pipeline transportation revenue	$ 15,323	$ 17,058	$ 31,215	$ 33,038
Crude oil sales, net of purchases(1)	5,093	5,846	10,752	11,372
Net revenue before operating expenses	20,416	22,904	41,967	44,410
Expenses:				
Operating	8,260	9,512	16,266	18,919
Transition costs		50		116
Depreciation and amortization	2,859	2,794	5,681	5,493
Total expenses	11,119	12,356	21,947	24,528
Operating income(5)	$ 9,297	$ 10,548	$ 20,020	$ 19,882
Operating Data:				
Line 2000 and Line 63 pipeline throughput (bpd)(2)	156.5	173.5	157.9	171.1
Rocky Mountain Operations:				
Pipeline transportation revenue	$ 10,321	$ 10,682	$ 19,720	$ 15,771
Expenses:				
Operating	6,084	5,557	10,726	7,356
Transition costs		1,094	397	1,860
Depreciation and amortization	1,346	1,523	2,705	1,911
Total expenses	7,430	8,174	13,828	11,127
Share of net income of Frontier	386	227	727	495
Operating income(5)	$ 3,277	$ 2,735	$ 6,619	$ 5,139
Operating Data:				
Salt Lake City Core system throughput (bpd)(2)(4)	64.7	71.9	64.7	71.3
Western Corridor system throughput (bpd)(2)(4)	17.6	13.4	15.6	15.4
AREPI pipeline throughput (bpd)(2)	41.4	47.3	38.5	44.6
Frontier pipeline throughput (bpd)(2)(3)	41.0	45.5	38.2	44.7

	For the Three Months Ended,		For the Six Months Ended,	
	June 30, 2003	June 30, 2002	June 30, 2003	June 30, 2002
	(in thousands) (unaudited)			
Income Statement Reconciliation				
Operating income from above:				
West Coast Operations	$ 9,297	$ 10,548	$ 20,020	$ 19,882

	For the Three Months Ended,		For the Six Months Ended,	
Rocky Mountain Operations	3,277	2,735	6,619	5,139
Total operating income from above	12,574	13,283	26,639	25,021
Less: General and administrative	3,002	1,543	6,984	2,885
Operating income	9,572	11,740	19,655	22,136
Other income	110	166	145	283
Interest income	46	64	102	249
Interest expense	(4,102)	(2,338)	(8,148)	(3,855)
Net income	$ 5,626	$ 9,632	$ 11,754	$ 18,813

(1) The above amounts are net of purchases of $87,935 and $79,903 for the three months ended June 30, 2003 and 2002, respectively. The above amounts are net of purchases of $174,557 and $139,832 for the six months ended June 30, 2003 and 2002, respectively.

(2) bpd is barrels per day.

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

(4) This amount represents throughput for the period of March 1, 2002 to June 30, 2002 and the six months ended June 30, 2003, as this system was acquired on March 1, 2002.

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

Three Months Ended June 30, 2003 Compared to Three Months Ended June 30, 2002

Net Income. Consolidated net income totaled $5.6 million for the three months ended June 30, 2003, as compared to $9.6 million for the corresponding period in 2002, a decrease of $4.0 million, or 42%. The results for the three months ended June 30, 2002 are for a period prior to the Partnership's initial public offering in July 2002. Net income for the three months ended June 30, 2003, reflects lower revenue primarily due to lower West Coast pipeline throughput, and lower gathering and blending margins, increased general and administrative expense as a result of our significant growth in 2002 and becoming a public company, and increased interest expense related to the fixed-rate debt in our post initial public offering capital structure compared to the floating-rate debt for the corresponding period in 2002. These factors were partially offset by lower operating and transition costs in the current quarter.

West Coast Operations

Operating income for our West Coast operations totaled $9.3 million for the three months ended June 30, 2003, compared to $10.5 million for the corresponding period in 2002, a decrease of $1.2 million, or 11%. This decrease was primarily due to a reduction in pipeline transportation revenue of $1.7 million as average daily pipeline throughput decreased to 156,500 barrels per day for the three months ended June 30, 2003 as compared to 173,500 barrels per day for the corresponding period in 2002. Offshore California ("OCS") throughput transported to Los Angeles was lower during the three months ended June 30, 2003 as compared to the corresponding period in 2002 primarily due to

maintenance downtime at an on-shore processing facility, as well as normal production decline. In addition, refinery maintenance in Los Angeles and increased demand for light crude oil at refineries in Bakersfield reduced throughput transported to Los Angeles. Our crude oil sales, net of purchases, also decreased $0.8 million for the three months ended June 30, 2003 as compared to the corresponding period in 2002 as we experienced lower margins on our gathering and blending operations. These decreases in operating income were partially offset by a decrease in operating expense of $1.3 million for the three months ended June 30, 2003 as compared to the corresponding period in 2002. This decrease in operating expense was due to a reduction in blending and power costs resulting from the reduced throughput as well as lower field maintenance expenses.

Rocky Mountain Operations

Operating income for our Rocky Mountain operations totaled $3.3 million for the three months ended June 30, 2003, compared to $2.7 million for the corresponding period in 2002, an increase of $0.6 million, or 22%. This increase was primarily the result of a decrease in transition costs from the prior year of $1.1 million, partially offset by a decrease in pipeline transportation revenue of $0.4 million. This decrease in revenue was primarily due to refinery maintenance downtime that reduced demand for crude oil at Salt Lake City refineries, which resulted in lower pipeline throughput.

Pipeline Transportation Revenue. Consolidated pipeline transportation revenue totaled $25.6 million for the three months ended June 30, 2003 compared to $27.7 million for the corresponding period in 2002, a decrease of $2.1 million, or 8%. This decrease was primarily attributable to our West Coast operations, where revenue decreased by $1.7 million compared to the corresponding period in 2002 due to lower throughput. OCS throughput transported to Los Angeles was lower during the three months ended June 30, 2003 as compared to the corresponding period in 2002 primarily due to maintenance downtime at an on-shore processing facility, as well as normal production decline. In addition, refinery maintenance in Los Angeles and increased demand for light crude oil at refineries in Bakersfield reduced throughput transported to Los Angeles. Rocky Mountain revenue for the three months ended June 30, 2003 decreased by $0.4 million compared to the corresponding period in 2002, due to refinery maintenance downtime that reduced demand for crude oil at Salt Lake City refineries, and a precautionary reduction in line pressure that reduced throughput on a Salt Lake City Core system pipeline pending pipeline integrity testing, which has now been completed with pressure restored to normal, partially offset by new movements on the Western Corridor system.

Crude Oil Sales, net. The PMT gathering and blending system generated crude oil sales, net of purchases for the three months ended June 30, 2003 of $5.1 million on total sales of $93.0 million as compared to crude oil sales, net of purchases of $5.8 million on total sales of $85.7 million for the corresponding period in 2002. The increase in total sales in 2003 is the result of increased crude oil prices. The decrease in crude oil sales, net of purchases in 2003 is due to lower margins on our gathering and blending operations. We consider this activity to be ancillary to our pipeline transportation operations.

Operating Expense. Consolidated operating expense totaled $14.3 million for the three months ended June 30, 2003, compared to $15.1 million for the corresponding period in 2002, a decrease of $0.8 million, or 5%. West Coast operating expense decreased by $1.3 million due to lower blending and power costs, which vary with throughput levels, as well as lower field maintenance expenses. Rocky Mountain operating expense increased $0.5 million, the result of an increase in field maintenance expenses attributable to our performance of maintenance services in the second quarter of 2003 that had for the corresponding period in 2002 been performed for a fee by the seller of the Western Corridor system and Salt Lake City Core system assets. Correspondingly, transition costs, which reflect the cost of these services performed by the seller, declined in the second quarter of 2003, compared to the corresponding period in 2002, by $1.1 million, as we undertook the performance of these functions.

Transition Costs. No transition costs were incurred for the three months ended June 30, 2003. Consolidated transition costs of $1.1 million for the three months ended June 30, 2002 consisted of payments to the seller for certain interim operations support and financial systems services related to the acquisition of the Western Corridor system and Salt Lake City Core system assets.

General and Administrative Expense. Consolidated general and administrative expense was $3.0 million for the three months ended June 30, 2003, compared to $1.5 million for the corresponding period in 2002, an increase of $1.5 million, or 100%. This increase includes $0.8 million of expense for our new long-term incentive plan, with the balance attributable to additional costs incurred as a result of the acquisition of the Western Corridor system and Salt Lake City Core system assets and increased costs associated with being a public company.

Depreciation and Amortization Expense. Consolidated depreciation and amortization expense was $4.2 million for the three months ended June 30, 2003, compared to $4.3 million for the corresponding period in 2002, a decrease of $0.1 million, or 2%.

Interest Expense. Consolidated interest expense was $4.1 million for the three months ended June 30, 2003, compared to $2.3 million for the corresponding period in 2002, an increase of $1.8 million, or 78%. This increase was due to an increase in the interest rate on outstanding borrowings during the three months ended June 30, 2003, which averaged 7.3% as compared to 3.5% during the corresponding period in 2002, reflecting the cost of our interest rate swap agreements in which we fixed the interest rates on $170.0 million of our post initial public offering debt. This increase was partially offset by a decrease in the average daily debt balance, which was $225.0 million during the three months ended June 30, 2003, as compared to $268.3 million during the corresponding period in 2002.

Share of Net Income of Frontier. Our share of net income of Frontier was $0.4 million for the three months ended June 30, 2003, compared to $0.2 million for the corresponding period in 2002, an increase of $0.2 million, or 100%.

Six Months Ended June 30, 2003 Compared to Six Months Ended June 30, 2002

Net Income. Consolidated net income totaled $11.8 million for the six months ended June 30, 2003, compared to $18.8 million for the corresponding period in 2002, a decrease of $7.0 million, or 37%. This decrease was primarily attributable to lower West Coast pipeline throughput, increased depreciation expense related to our March 1, 2002, acquisition of Rocky Mountain assets, increased general and administrative expense and increased interest expense associated with our post initial public offering capital structure. These decreases to net income were partially offset by increased revenue in the Rocky Mountain region, primarily due to a full six months of operations of the Western Corridor system and Salt Lake City Core system assets acquired on March 1, 2002, and lower West Coast operating expenses and Rocky Mountain transition costs.

West Coast operations

Operating income for our West Coast operations totaled $20.0 million for the six months ended June 30, 2003, which was largely unchanged from the corresponding period in 2002 as lower revenue was offset by decreased operating expense. Pipeline transportation revenue for the six months ended June 30, 2003 was $1.8 million lower than for the corresponding period in 2002 as average daily pipeline throughput decreased to 157,900 barrels per day for the six months ended June 30, 2003 as compared to 171,100 barrels per day for the corresponding period in 2002. OCS throughput transported to Los Angeles was lower during the six months ended June 30, 2003 as compared to the corresponding period in 2002 primarily due to maintenance downtime at an on-shore processing facility as well as normal production decline. In addition, refinery maintenance in Los Angeles and increased mid-barrel crude oil ("MBCO") demand in San Francisco reduced MBCO throughput transported to

Los Angeles. Our crude oil sales, net of purchases, also decreased $0.6 million during the six months ended June 30, 2003 as we experienced lower margins on our gathering and blending operations. The decrease in revenue for the six months ended June 30, 2003 was offset by lower operating expense of $2.7 million due to decreased right-of-way expense and lower blending and power expense.

Rocky Mountain operations

Operating income for our Rocky Mountain operations totaled $6.6 million for the six months ended June 30, 2003, compared to $5.1 million for the corresponding period in 2002, an increase of $1.5 million, or 29%. This increase was primarily due to a full six months of operations of the Western Corridor system and Salt Lake City Core system assets, which were acquired on March 1, 2002.

Pipeline Transportation Revenue. Consolidated pipeline transportation revenue totaled $50.9 million for the six months ended June 30, 2003, compared to $48.8 million for the corresponding period in 2002, an increase of $2.1 million, or 4%. This increase was attributable to our Rocky Mountain operations, where revenue increased by $3.9 million compared to the corresponding period in 2002 due to revenue generated by the Western Corridor system and the Salt Lake City Core system assets. Average daily pipeline throughput was lower during the six months ended June 30, 2003 as compared to the period of March 1, 2002 to June 30, 2002 due to Salt Lake City refinery maintenance, and a precautionary reduction in line pressure that reduced throughput on a Salt Lake City Core system pipeline pending pipeline integrity testing, which has now been completed with pressure restored to normal. The increase in Rocky Mountain pipeline transportation revenue for the six months ended June 30, 2003 was partially offset by a decrease in West Coast revenue for the same period of $1.8 million due to lower average daily throughput attributable to lower OCS throughput transported to Los Angeles due to maintenance downtime at an on-shore processing facility as well as normal production decline. In addition, refinery maintenance in Los Angeles and increased MBCO demand in San Francisco reduced MBCO throughput transported to Los Angeles.

Crude Oil Sales, net. The PMT gathering and blending system generated crude oil sales, net of purchases for the six months ended June 30, 2003 of $10.8 million on total sales of $185.3 million as compared to crude oil sales, net of purchases of $11.4 million on total sales of $151.2 million for the corresponding period in 2002. The increase in total sales in 2003 is the result of increased crude oil prices. The decrease in crude oil sales, net of purchases in 2003 is due to lower margins on our gathering and blending operations. We consider this activity to be ancillary to our pipeline transportation operations.

Operating Expense. Consolidated operating expense totaled $27.0 million for the six months ended June 30, 2003, compared to $26.3 million for the corresponding period in 2002, an increase of $0.7 million, or 3%. This increase was related primarily to our Rocky Mountain operations, where operating expense increased by $3.8 million due to a full six months of operations of the Western Corridor system and the Salt Lake City Core system assets compared to four months of operations for the corresponding period in 2002. This was partially offset by $1.5 million in transition cost savings as discussed below. Operating expense for our West Coast operations decreased by $2.7 million primarily due to decreased right-of-way expense resulting from the relinquishment of certain unused rights-of-way and due to lower blending and power expense, which vary with throughput levels. West Coast power expense did, however, increase on a per unit of consumption basis. We also experienced higher property and casualty insurance expense and property tax expense in 2003 for both our West Coast and Rocky Mountain operations.

Transition Costs. Consolidated transition costs were $0.4 million for the six months ended June 30, 2003 compared to $2.0 million for the corresponding period in 2002, a decrease of $1.6 million, or 80%. Transition costs in 2003 consisted only of employee transition bonus payments, whereas transition costs in 2002 consisted of payments to the seller of the Rocky Mountain assets for certain interim operations support and financial systems services related to the acquisition of the

Western Corridor system and Salt Lake City Core system assets in addition to employee transition bonus payments.

General and Administrative Expense. Consolidated general and administrative expense was $7.0 million for the six months ended June 30, 2003 compared to $2.9 million for the corresponding period in 2002, an increase of $4.1 million, or 141%. This increase includes $1.8 million of expense for our new long-term incentive plan, with the balance attributable to additional costs incurred as a result of the acquisition of the Western Corridor system and Salt Lake City Core system assets and increased costs associated with being a public company.

Depreciation and Amortization Expense. Consolidated depreciation and amortization expense was $8.4 million for the six months ended June 30, 2003, compared to $7.4 million for the corresponding period in 2002, an increase of $1.0 million, or 14%. This increase consists of $0.8 million related to the acquisition of the Western Corridor system and the Salt Lake City Core system assets.

Interest Expense. Consolidated interest expense was $8.1 million for the six months ended June 30, 2003, compared to $3.9 million for the corresponding period in 2002, an increase of $4.2 million, or 108%. This increase was due to an increase in the interest rate on outstanding borrowings during the six months ended June 30, 2003, which averaged 7.2% as compared to 3.2% during the corresponding period in 2002, reflecting the cost of our interest rate swap agreements in which we fixed the interest rates on $170.0 million of our post initial public offering debt. This increase was partially offset by a decrease in the average daily debt balance, which was $225.0 million during the six months ended June 30, 2003, as compared to $240.0 million during the corresponding period in 2002.

Share of Net Income of Frontier. Our share of net income of Frontier was $0.7 million for the six months ended June 30, 2003, compared to $0.5 million for the corresponding period in 2002, an increase of $0.2 million, or 40%.

Liquidity and Capital Resources

Historically, we have satisfied our working capital requirements and funded our capital expenditures with cash generated from operations and from our credit facilities. We believe that cash generated from operations and our borrowing capacity will be sufficient to meet our working capital requirements, anticipated maintenance capital expenditures and scheduled debt payments for at least the next several years. We expect to fund any future acquisitions with the proceeds of borrowings under our revolving credit facility and the issuance of additional units. Our ability to satisfy our debt service obligations, fund planned capital expenditures, make acquisitions and pay distributions to our unitholders will depend upon, among other things, our future operating performance. Our operating performance is primarily dependent on the volume of crude oil we transport and, with respect to the Pacific Terminals operations, the volume of oil we store, which could be affected by a decrease in the volume of crude oil produced from the oil fields or processed by the refineries served by our pipelines. These factors, which are affected by prevailing economic conditions in the crude oil industry and financial, business and other factors, some of which are beyond our control, could significantly impact future results.

On July 18, 2003, the Partnership declared a cash distribution of $0.4625 per limited partner unit, payable on August 14, 2003 to unitholders of record as of July 31, 2003.

On July 31, 2003, the Partnership announced that it expects its cash distribution to increase from $0.4625 per unit to $0.4875 per unit beginning with the third quarter 2003 as a result of additional income anticipated from the acquisition of the Pacific Terminals storage and distribution assets.

27

On August 1, 2003, the Partnership filed a universal shelf registration statement on Form S-3 to register $550.0 million of equity securities and debt securities for issuance from time to time and in such amounts as determined by market conditions and the needs of the Partnership. The registration statement also covers, for possible future sales, up to 1,865,000 common units held by the General Partner, which acquired these common units as partial consideration for its contribution to the Partnership of assets and liabilities in connection with the Partnership's initial public offering.

Operating, Investing and Financing Activities

Net cash provided by operating activities was $19.2 million for the six months ended June 30, 2003 compared to $15.5 million for the corresponding period in 2002, an increase of $3.7 million, or 24%. This increase was primarily associated with the changes in working capital items, partially offset by lower net income.

Net cash used in investing activities was $1.1 million for the six months ended June 30, 2003 compared to $97.6 million for the corresponding period in 2002. The 2002 period included the acquisition of the Western Corridor system and Salt Lake City Core system assets on March 1, 2002. Capital expenditures were $1.2 million for the six months ended June 30, 2003, of which $0.7 million related to maintenance capital projects, $0.4 million related to expansion projects, and $0.1 million related to transition projects. Capital expenditures were $2.4 million for the six months ended June 30, 2002, of which $1.2 million related to maintenance capital projects, $0.6 million related to expansion projects and $0.6 million related to transition projects.

Net cash used in financing activities of $19.8 million for the six months ended June 30, 2003 consisted of distributions to the limited partners and the general partner. Net cash provided by financing activities of $89.6 million for the six months ended June 30, 2002 consisted primarily of proceeds from a bank facility of $87.0 million used to fund the acquisition of the Western Corridor system and Salt Lake City Core system assets. Contributions of members and distributions to members during the six months ended June 30, 2002 were $8.7 million and $6.0 million, respectively.

Capital Requirements

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

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

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

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

We forecast maintenance capital expenditures of $2.9 million, expansion capital expenditures of $2.1 million and transitional capital expenditures of $0.6 million for 2003. These forecast expenditures include capital expenditures expected in connection with the Pacific Terminals storage and distribution system, for the period of August to December 2003.

The purchase price for the assets comprising the Pacific Terminals storage and distribution system is $158.2 million, plus adjustments for certain pre-closing capital expenditures and other costs and the closing date value of displacement oil and warehouse inventory, all of which it is estimated will total $9 million. At the closing of the purchase on July 31, 2003, $159.3 million of the purchase price was

28

paid with proceeds of $149.0 million from borrowings under the Partnership's $200 million revolving credit facility and $10.3 million from cash on hand. The balance of the purchase price is expected to be paid in the third quarter of 2003. In addition, an estimated $3 million of transaction costs and liabilities have or will be paid or assumed by Pacific Terminals in connection with the acquisition.

We have been evaluating the feasibility of developing a deep-water bulk liquid petroleum import facility at the Port of Los Angeles and recently signed a non-binding memorandum of intent with a potential customer for the import facility. We have also submitted an "Application for Development Projects" with the Port of Los Angeles. During the second half of 2003, we will determine the feasibility of the project as we pursue a program of public and regulatory involvement.

Right-of-Way Obligations

We have secured various rights-of-way for our pipeline systems under right-of-way agreements, certain of which expire at various times through 2035, that provide for annual payments to third parties for access and the right to use their properties. Due to the nature of our operations, we expect to continue making payments and renewing the right-of-way agreements indefinitely. Annual amounts payable under certain of the right-of-way agreements are subject to periodic fair market and inflation adjustments.

Right-of-way payments, which are included in operating expense, were $0.6 million during each of the three month periods ended June 30, 2003 and June 30, 2002. Right-of-way payments were $1.4 million and $2.0 million during the six months ended June 30, 2003 and 2002, respectively.

Credit Facilities

The Partnership's long-term debt obligations at June 30, 2003 and December 31, 2002 are shown below:

	June 30, 2003	December 31, 2002
	(in thousands)	
	(unaudited)	
Senior secured revolving credit facility	$	$
Senior secured term loan facility	225,000	225,000
Total	225,000	225,000
Less current portion		
Long-term debt	$ 225,000	$ 225,000

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

The revolving credit facility is available for general partnership purposes, including working capital, letters of credit and distributions to unitholders and to finance future acquisitions, including the acquisition of the assets comprising the Pacific Terminals storage and distribution system. The revolving credit facility has a borrowing sublimit of $45.0 million for working capital, letters of credit and distributions to unitholders. The revolving credit facility was undrawn except for letters of credit outstanding totaling $10.3 million at June 30, 2003. On July 31, 2003 $149.0 was drawn on the revolving credit facility to fund, in part, the acquisition of the assets comprising the Pacific Terminals storage and distribution system.

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

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

The facilities are guaranteed by the Partnership and certain of PEG's subsidiaries. The facilities are fully recourse to PEG and the guarantors, but non-recourse to our General Partner. Obligations under the facilities are or will be secured by pledges of membership interests in and assets of PEG's subsidiaries, subject to certain limited exceptions and the approval of certain regulatory authorities. On July 31, 2003, pursuant to our credit agreement, we filed an application with the California Public Utilities Commission seeking authority for PPS and Pacific Terminals to guarantee up to $176.0 million and $167.0 million, respectively, of PEG's obligations under the credit agreement, including its obligations to repay amounts borrowed under the revolving credit facility and the term loan facility, and to secure such guarantees with mortgages or other encumbrances against certain of their properties.

Indebtedness under the facilities bear interest at the Partnership's option, at either (i) the base rate, which is equal to the higher of the prime rate as announced by Fleet National Bank or the Federal Funds rate plus 0.50% (each plus an applicable margin ranging from 0% to 0.50% for the revolving credit facility and ranging from 0.50% to 0.75% for the term loan facility) or (ii) LIBOR plus an applicable margin for the revolving credit facility ranging from 1.25% to 2.50% and the term loan facility ranging from 2.50% to 2.75%. The applicable margins are subject to change based on the credit rating of the facilities or, if they are not rated, the credit rating of PEG. As a result of the acquisition of the assets that comprise the Pacific Terminals storage and distribution system on July 31, 2003, the applicable margin will be increased by an additional 0.50% until April 26, 2004, or until we successfully conclude an equity offering that reduces certain ratios to specified levels, whichever is earlier.

PEG will incur a per annum commitment fee margin which ranges from 0.25% to 0.50% on the unused portion of the revolving credit facility. The credit agreement prevents PEG from declaring dividends or distributions if any event of default, as defined in the credit agreement, occurs or would result from such declaration. The credit agreement also contains covenants requiring PEG, including certain of its subsidiaries, to maintain specified financial ratios. In addition, the credit agreement contains other restrictive covenants.

In August and September 2002, PEG entered into interest rate swap agreements pursuant to which it hedged its exposure to variability in future cash flows attributable to the LIBOR interest payments due on $170.0 million outstanding under the term loan facility. The average swap rate on this $170.0 million of debt is approximately 4.25%, resulting in an all-in interest rate on the $170.0 million of debt of approximately 7.00% (including the current applicable margin of 2.75%), plus the 0.50% increase resulting from the Pacific Terminals acquisition, as described above. These interest rate swap agreements are described further in "Note 1 Summary of Significant Accounting Policies" in the accompanying condensed consolidated financial statements and "Item 3 Quantitative and Qualitative Disclosures About Market Risk" below.

30

Universal Shelf Registration

On August 1, 2003, we filed a universal shelf registration statement on Form S-3 to register $550.0 million of equity securities and debt securities for issuance from time to time and in such amounts as is determined by market conditions and the needs of the Partnership. The registration statement also covers, for possible future sales, up to 1,865,000 common units held by the General Partner, which acquired these common units as partial consideration for its contribution to the Partnership of assets and liabilities in connection with the Partnership's initial public offering.

Accounting Pronouncements

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

ITEM 3. Quantitative and Qualitative Disclosures About Market Risk

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

Although we generally do not own the crude oil that we transport in our pipelines, we purchase some crude oil for subsequent blending, transportation and resale primarily in the Los Angeles Basin. We use, on a limited basis, certain derivative instruments (principally futures and options) to hedge our exposure to market price volatility related to our inventory of crude oil. We do not enter into speculative derivative transactions. The derivative instruments are included in other assets in the accompanying balance sheets. Changes in the fair value of our derivatives are recognized in net income. For the three and six months ended June 30, 2003, revenues are net of $0.1 million and $0.3 million related to changes in the fair value of our derivative instruments for marketing activities.

In August and September 2002, PEG entered into three interest rate swap agreements pursuant to which it executed five interest rate swap transactions that mature in 2009, totaling $140.0 million, and two interest rate swap transactions that mature in 2007, totaling $30.0 million. The Partnership designated these swaps as a hedge of its exposure to variability in future cash flows attributable to the LIBOR interest payments due on $170.0 million outstanding under PEG's term loan facility. The average swap rate on this $170.0 million of debt is approximately 4.25%, resulting in an all-in interest rate on the $170.0 million of debt of approximately 7.00% (including the current applicable margin of 2.75%).

As a result of the purchase of the assets that comprise the Pacific Terminals storage and distribution system on July 31, 2003, the applicable margin increased by a margin of 0.50% and will remain at that level until April 26, 2004, or until the Partnership successfully concludes an equity offering that reduces certain ratios to specified levels, whichever is earlier. The 2.75% applicable margin rate referenced in the preceding paragraph does not include this increase.

As of June 30, 2003, interest rates, as measured by market quotations for the future periods covered by the interest rate swap agreements, had declined as compared to August and September 2002, when PEG entered into these interest rate swap agreements. This decline resulted in an unrealized loss of $12.4 million on the aggregate interest rate hedge, which is recorded as a liability at June 30, 2003. The $12.4 million liability is shown on the condensed consolidated balance sheet in two components, a current liability of $5.2 million, and a long term liability of $7.2 million. The unrealized loss reflecting the decline in interest rates from December 31, 2002, is shown in "other comprehensive income," a component of partners' capital, and not in the condensed consolidated

income statement. Should interest rates remain unchanged from the June 30, 2003 market quotations for these future periods, actual losses realized on the interest rate swap agreements in each of the future periods would be offset by the benefit of lower floating rates in those periods, such that total net interest expense on the $170.0 million of hedged debt would be fixed at the all-in interest rate of approximately 7.00%, plus the 0.50% increase resulting from the Pacific Terminals acquisition, as described above.

We are subject to risks resulting from interest rate fluctuations as interest on the remaining $55.0 million outstanding under our term loan facility is based on variable rates. If the LIBOR rate were to increase 1.00% in 2003 as compared to the rate at June 30, 2003, our interest expense for 2003 would increase $0.6 million based on the $55.0 million outstanding on our term loan facility at June 30, 2003, which has not been hedged. In addition, as a result of the acquisition of the Pacific Terminals storage and distribution system assets on July 31, 2003, our borrowings under the revolving credit facility increased by $149.0 million. If the LIBOR rate on this debt were to increase by 1.00% in 2003 as compared to the rate at June 30, 2003, our interest expense for the year ended December 31, 2003 would increase by $0.6 million based on the additional $149.0 million outstanding on our revolving credit facility at July 31, 2003.

ITEM 4. Controls and Procedures

Disclosure Controls and Procedures

As of the end of the quarterly period ended June 30, 2003, Irvin Toole, Jr., our Chief Executive Officer, and Gerald A. Tywoniuk, our Chief Financial Officer, evaluated the effectiveness of our disclosure controls and procedures. Based on the evaluation, they believe that:

- our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms; and

- our disclosure controls and procedures were effective to ensure that material information was accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

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, 2003 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 5. Other Information

By consent action in lieu of its 2003 annual meeting of stockholders, the stockholder of the General Partner elected the following individuals to serve on the board of directors of the General Partner effective as of June 27, 2003 and until the next annual meeting: Douglas L. Polson, Philip F. Anschutz, Clifford P. Hickey, David L. Lemmon, Jim E. Shamas, Robert F. Starzel and Irvin Toole, Jr. Mr. Polson serves as Chairman.

Craig D. Slater, who was elected to the board of directors in December 2001, did not stand for re-election.

New York Stock Exchange rules require the General Partner to have at least three independent directors. Mr. Lemmon, Mr. Shamas and Mr. Starzel are independent directors and serve on the audit and compensation committees. Mr. Lemmon and Mr. Shamas serve on the conflicts committee. Mr. Lemmon, Mr. Shamas, Mr. Starzel and Mr. Polson serve on the nominating and governance committee.

PART II. OTHER INFORMATION

ITEM 1. Legal Proceedings

See discussion of legal proceedings in "Note 6 Commitments and Contingencies" in the accompanying condensed consolidated financial statements.

ITEM 6. Exhibits and Reports on Form 8-K

(a)

Exhibits

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

Exhibit Number	Description
Exhibit 3.8	Amendment No. 1 to First Amended and Restated Agreement of Limited Partnership of Pacific Energy Partners, L.P., dated August 1, 2003 (Incorporated by reference to Pacific Energy Partners, L.P.'s Form S-3 filed on August 1, 2003, Exhibit 3.3)
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, as amended
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, as amended
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.,

Exhibit Number	Description
	pursuant to 18 U.S.C. §1350

(b)

Reports on Form 8-K:

Form 8-K as filed on April 30, 2003 concerning the Partnership's 1st quarter 2003 earnings release on April 30, 2003.

Form 8-K as filed on June 4, 2003 concerning the Partnership's press release on June 4, 2003 announcing the issuance by the CPUC of a draft proposed decision by the assigned administrative law judge relating to the pending acquisition of the assets comprising the Pacific Terminals storage and distribution system.

Form 8-K as filed on June 10, 2003 concerning the Partnership's press release on June 10, 2003 announcing the resolution of a rate complaint with Sinclair Oil Corporation.

Form 8-K as filed on July 14, 2003 concerning the Partnership's press release on July 10, 2003 announcing the pending purchase of the assets comprising the Pacific Terminals storage and distribution system from Southern California Edison Company was approved by the CPUC.

Form 8-K as filed on July 30, 2003 concerning the Partnership's 2nd quarter 2003 earnings release on July 30, 2003.

Form 8-K as filed on July 31, 2003 concerning the Partnership's press release on July 31, 2003 announcing a cash distribution increase and the closing of the EPTC facilities acquisition.

Form 8-K as filed on August 1, 2003 concerning the filing of the consolidated balance sheets of Pacific Energy GP, Inc., as of December 31, 2002 and as of June 30, 2003 (unaudited).

SIGNATURES

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

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

August 7, 2003 By: /s/ IRVIN TOOLE, JR.

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

August 7, 2003 By: /s/ GERALD A. TYWONIUK

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

EXHIBIT INDEX

Exhibit Number	Description
Exhibit 3.8	Amendment No. 1 to First Amended and Restated Agreement of Limited Partnership of Pacific Energy Partners, L.P., dated August 1, 2003 (Incorporated by reference to Pacific Energy Partners, L.P.'s Form S-3 filed on August 1, 2003, Exhibit 3.3)
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, as amended
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, as amended
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