Perotti Daniel Stanley
Form 4
November 28, 2017

FORM 4

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

OMB APPROVAL

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STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

(Print or Type Responses)

1. Name and Address of Reporting Person *
Perotti Daniel Stanley

(Last) (First) (Middle)

C/O PENNYMAC FINANCIAL SERVICES, INC., 3043 TOWNSGATE ROAD

(Street)

WESTLAKE VILLAGE, CA 91361

(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
PENNYMAC FINANCIAL SERVICES, INC. [PFSI]

3. Date of Earliest Transaction (Month/Day/Year)
11/27/2017

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

_____ Director _____ 10% Owner
__X__ Officer (give title below) _____ Other (specify below)
Deputy CFO

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			
Class A Common Stock	11/27/2017		M		2,400 (1)	A	$ 0 (2)	2,400	I	The Perotti Family Trust
Class A Common Stock	11/27/2017		S		2,400 (3)	D	$ 20.0021 (4)	0	I	The Perotti Family Trust
Class A Common	11/28/2017		M		3,042 (1)	A	$ 0 (2)	3,042	I	The Perotti

Stock										Family Trust
Class A Common Stock	11/28/2017		S		3,042 (3)	D	$ 20.0033 (4)	0	I	The Perotti Family Trust
Class A Common Stock								11,405 (5)	D	

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

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SEC 1474 (9-02)

Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security (Instr. 3)	2. Conversion or Exercise Price of Derivative Security	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any (Month/Day/Year)	4. Transaction Code (Instr. 8)		5. Number of Derivative Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)		6. Date Exercisable and Expiration Date (Month/Day/Year)		7. Title and Amount Underlying Securitie (Instr. 3 and 4)	
				Code	V	(A)	(D)	Date Exercisable	Expiration Date	Title	Amour or Numbe of Shar
Cl A Units of Private Nat'l Mortgage Acceptance Company, LLC	(6)	11/27/2017		M			2,400	(6)	(6)	Class A Common Stock	2,40 (1)
Cl A Units of Private Nat'l Mortgage Acceptance Company, LLC	(6)	11/28/2017		M			3,042	(6)	(6)	Class A Common Stock	3,04 (1)
Nonstatutory Stock Option (Right to Buy)	$ 21.03							06/13/2014	06/12/2023	Class A Common Stock	2,52 (7)
	$ 17.26							02/26/2015	02/25/2024		

Nonstatutory Stock Option (Right to Buy)				Class A Common Stock	16,88 [8]
Nonstatutory Stock Option (Right to Buy)	$ 17.52	03/03/2016	03/02/2025	Class A Common Stock	16,48 [9]
Nonstatutory Stock Option (Right to Buy)	$ 11.28	03/07/2017	03/06/2026	Class A Common Stock	16,61 [10]
Nonstatutory Stock Option (Right to Buy)	$ 18.05	03/06/2018	03/05/2027	Class A Common Stock	22,50 [11]

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
Perotti Daniel Stanley C/O PENNYMAC FINANCIAL SERVICES, INC. 3043 TOWNSGATE ROAD WESTLAKE VILLAGE, CA 91361			Deputy CFO	

Signatures

/s/ Derek W. Stark, attorney-in-fact for Mr. Perotti	11/28/2017
**Signature of Reporting Person	Date

Explanation of Responses:

* If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

(1) Represents shares of Class A Common Stock received upon the exchange of Class A Units of Private National Mortgage Acceptance Company, LLC.

(2) Pursuant to the terms of an exchange agreement, Class A Units of Private National Mortgage Acceptance Company, LLC are exchangeable for shares of Class A Common Stock of the Issuer on a one-for-one basis, subject to customary conversion rate adjustments.

(3) These shares of Class A Common Stock were sold pursuant to a 10b5-1 plan.

(4) The price reported is the weighted average price of multiple transactions ranging from $20.00 to $20.05. The reporting person hereby undertakes to provide upon request to the SEC, the Issuer or a security holder of the Issuer the number of Class A Common Stock and the prices at which the transactions were effected.

(5) The reported amount consists of 9,002 restricted stock units and 2,403 shares of Class A Common Stock. The restricted stock units are to be settled in an equal number of shares of Class A Common Stock upon vesting.

(6)

Pursuant to the terms of an exchange agreement, Class A Units of Private National Mortgage Acceptance Company, LLC are exchangeable for shares of Class A Common Stock of the Issuer on a one-for-one basis, subject to customary conversion rate adjustments, from and after the closing of PennyMac Financial, Inc,'s initial public offering, and after the expiration of a lock-up agreement.

(7) This nonstatutory stock option to purchase 2,523 shares of Class A Common Stock of the Issuer will vest as to one-third of the optioned shares on each of the first, second and third anniversaries of the grant date, subject to the Reporting Person's continued service through each date.

(8) This nonstatutory stock option to purchase 16,881 shares of Class A Common Stock of the Issuer will vest as to one-third of the optioned shares on each of February 26, 2015, 2016 and 2017, subject to the Reporting Person's continued service through each date.

(9) This nonstatutory stock option to purchase 16,481 shares of Class A Common Stock of the Issuer will vest as to one-third of the optioned shares on each of March 3, 2016, 2017 and 2018, subject to the Reporting Person's committed service through each date.

(10) This nonstatutory stock option to purchase 16,615 shares of Class A Common Stock of the Issuer will vest as to one-third of the optioned shares on each of March 7, 2017, 2018 and 2019, subject to the Reporting Person's committed service through each date.

(11) This nonstatutory stock option to purchase 22,506 shares of Class A Common Stock of the Issuer will vest as to one-third of the optioned shares on each of March 6, 2018, 2019 and 2020, subject to the Reporting Person's committed service through each date.

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.

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See accompanying notes to condensed consolidated financial statements.

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

	For the Three Months Ended		For the Nine Months Ended	
	September 30, 2003	September 30, 2002	September 30, 2003	September 30, 2002
	(in thousands) (unaudited)			
Pipeline transportation revenue	$ 24,282	$ 26,602	$ 74,187	$ 75,411
Storage and terminaling revenue	4,710		4,710	
Crude oil sales, net of purchases of $95,614 and $94,042 for the three months ended September 30, 2003 and 2002 and $269,141 and $233,874 for the nine months ended September 30, 2003 and 2002	7,126	5,606	18,908	16,978
Net revenue before operating expenses	36,118	32,208	97,805	92,389
Expenses:				
Operating	16,630	14,364	43,622	40,639
Transition costs		699	397	2,675
General and administrative	3,305	1,639	10,289	4,524
Depreciation and amortization	5,049	4,307	13,435	11,711

	For the Three Months Ended		For the Nine Months Ended	
	24,984	21,009	67,743	59,549
Share of net income of Frontier	414	471	1,141	966
Operating income	11,548	11,670	31,203	33,806
Other income	83	133	228	416
Interest income	30	65	132	314
Interest expense	(4,782)	(3,510)	(12,930)	(7,365)
Net income	$ 6,879	$ 8,358	$ 18,633	$ 27,171
Net income for the general partner interest for the three and nine months ended September 30, 2003 and period from July 26 through September 30, 2002	$ 138	$ 108	$ 373	
Net income for the limited partner interests for the three and nine months ended September 30, 2003 and period from July 26 through September 30, 2002	$ 6,741	$ 5,305	$ 18,260	
Basic net income per limited partner unit for the three and nine months ended September 30, 2003 and for the period from July 26 through September 30, 2002	$ 0.30	$ 0.25	$ 0.85	
Diluted net income per limited partner unit for the three and nine months ended September 30, 2003 and for the period from July 26 through September 30, 2002	$ 0.30	$ 0.25	$ 0.84	
Weighted average limited partner units outstanding for the three and nine months ended September 30, 2003 and for the period from July 26 through September 30, 2002:				
Basic	22,532	20,930	21,470	
Diluted	22,725	20,930	21,648	

See accompanying notes to condensed consolidated financial statements.

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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)

	Limited Partner Units		Limited Partner Amounts			Undistributed Employee Long-Term Incentive Compensation		
Balance, December 31, 2002	10,465	10,465	$ 163,172	$ 57,069	$ 2,329	$	$ (7,375)	$ 215,195
Net income			9,351	8,929	373			18,633
Distribution to partners			(14,542)	(14,522)	(593)			(29,657)
Issuance of common units, net of fees and offering expenses (note 6)	5,612		131,716					131,716
Redemption of common units held by general partner (note 6)	(1,727)		(40,780)					(40,780)
General partner contribution related to issuance of common units (note 6)					1,955			1,955
Undistributed employee compensation under long-term incentive plan (note 1)						2,636		2,636
Issuance of common units pursuant to long-term incentive plan	52		860		16	(1,473)		(597)
Change in fair value of interest rate hedging derivatives (note 1)							(845)	(845)
Balance, September 30, 2003	14,402	10,465	$ 249,757	$ 51,476	$ 4,080	$ 1,163	$ (8,220)	$ 298,256

See accompanying notes to condensed consolidated financial statements.

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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 Nine Months Ended	
	September 30, 2003	September 30, 2002	September 30, 2003	September 30, 2002
	(in thousands) (unaudited)			
Net income	$ 6,879	$ 8,358	$ 18,633	$ 27,171
Change in fair value of interest rate hedging derivatives (note 1)	4,143	(6,978)	(845)	(6,978)
Comprehensive income	$ 11,022	$ 1,380	$ 17,788	$ 20,193

See accompanying notes to condensed consolidated financial statements.

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

For the Nine Months Ended

	For the Nine Months Ended	
	September 30, 2003	September 30, 2002
	(in thousands) (unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 18,633	$ 27,171
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	13,435	11,711
Amortization of debt issue costs	745	217
Non-cash portion of employee compensation under long-term incentive plan	1,955	
Share of net income of Frontier	(1,141)	(966)
	33,627	38,133
Net changes in operating assets and liabilities:		
Accounts receivable	(7,215)	(17,915)
Due to related party	(667)	1,197
Crude oil inventory	2,161	1,082
Prepaid expenses	9	(2,161)
Other current and non-current assets	49	(6,609)
Accounts payable and accrued liabilities	760	3,614
Accrued expenses	902	8,733
Provision for loss on rate case litigation		(1,500)
Distributions from Frontier, net	1,777	1,244
Other current and non-current liabilities	1,998	2,897
	(226)	(9,418)
NET CASH PROVIDED BY OPERATING ACTIVITIES	33,401	28,715
CASH FLOWS FROM INVESTING ACTIVITIES		
Acquisition of pipeline and storage assets	(159,939)	(95,196)
Additions to property and equipment	(2,320)	(3,954)
Disposal of equipment	137	
NET CASH USED IN INVESTING ACTIVITIES	(162,122)	(99,150)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from issuance of common units	138,394	167,700
Capital contributions from the general partner	1,955	
Redemption of common units held by the general partner, net of underwriter's fees	(40,780)	
Common units issuance fees and offering expenses	(6,678)	(17,059)
Proceeds from issuance of debt	149,000	312,000
Repayments of debt	(90,000)	(268,333)
Capital contributions of members (pre initial public offering)		8,770
Distributions to members (pre initial public offering)		(16,000)
Distributions to general partner in connection with the initial public offering		(105,081)
Distributions to partners (post initial public offering)	(29,657)	
Due from related party		(122)

	For the Nine Months Ended	
NET CASH PROVIDED BY FINANCING ACTIVITIES	122,234	81,875
NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	(6,487)	11,440
CASH AND CASH EQUIVALENTS, beginning of reporting period	23,873	9,511
CASH AND CASH EQUIVALENTS, end of reporting period	$ 17,386	$ 20,951
Supplemental disclosures:		
Cash paid for interest	$ 11,716	$ 4,960
Non-cash financing and investing activities:		
Change in fair value of interest rate hedging derivatives	$ 845	$ 6,978
Issuance of common units upon vesting pursuant to long-term incentive plan	$ 1,473	$
Addition to equipment	$ 124	$

See accompanying notes to condensed consolidated financial statements.

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PACIFIC ENERGY PARTNERS, L.P.
Successor to Pacific Energy (Predecessor)
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
September 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 common units representing limited partner interests. The Partnership, which was formed by The Anschutz Corporation ("Anschutz") in February 2002, and its subsidiaries are engaged principally in the business of gathering, transporting, storing and distributing crude oil and other dark products in California and the Rocky Mountain region. Revenue is generated primarily by charging tariff rates for transporting crude oil on the Partnership's pipelines and by leasing capacity in its storage facilities. The Partnership also buys, blends and sells crude oil, activities that are complementary to the Partnership's pipeline transportation business. The Partnership's business operations are organized into two regional operating units: West Coast operations and Rocky Mountain operations.

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 system, (iii) Rocky Mountain Pipeline System LLC ("RMP"), owner of the Western Corridor and the Salt Lake City Core systems, (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"). 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 facility 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. On July 31, 2003, Pacific Terminals LLC ("Pacific Terminals"), a wholly owned indirect subsidiary of the Partnership acquired the black oil storage and pipeline distribution system assets of Edison Pipeline and Terminal Company, a division of Southern California Edison Company. The condensed consolidated financial statements reflect the ownership and results of operations of Pacific Terminals for the period from July 31, 2003 to September 30, 2003. All significant intercompany balances and transactions have been eliminated during the consolidation process.

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 nine months ended September 30, 2003 are not necessarily indicative of the results of operations for the full year. The financial data for the three and nine months ended September 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 nine months ended September 30, 2002 is derived from the unaudited combined financial statements of Pacific Energy (Predecessor) through July 25, 2002 and for the Partnership thereafter.

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 September 30, 2003 and December 31, 2002, owned 100% of PPS, PMT, RMP, AREPI and RPL. At September 30, 2003, PEG also owned 100% of Pacific Terminals.

PPS was formed in 1998. 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. Under the purchase agreement the purchase price was subject to adjustment based on operating results during the 24 months following the acquisition. The terms of the purchase also provided that the seller remain liable for various indemnity, product supply, and construction obligations for a period of time after the sale. On September 2, 2003, PMT and the seller entered into an agreement providing for the mutual release by each of them of substantially all of their respective obligations remaining to be performed in connection with PMT's purchase of these assets. Under the terms of the release agreement, PMT received $0.3 million in cash and $0.1 million in equipment. PMT in turn released the seller from a construction obligation as well as certain indemnity obligations and as a result, recorded a liability of $0.4 million.

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, known as the Western Corridor and the Salt Lake City Core systems, 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 was formed in 1987. AREPI 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 was formed in 1982. RPL 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 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 formed in February 2002 in connection with the acquisition on July 31, 2003 of the black oil storage and pipeline distribution system assets of Edison Pipeline and Terminal Company, a division of Southern California Edison, for a purchase price of approximately $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. The storage and distribution system assets acquired by Pacific Terminals consist of 70 miles of distribution pipelines in active black oil service and 34 storage tanks with a total of approximately 9.0 million barrels of storage capacity. Of this total capacity approximately 6.7 million barrels are in active commercial service, approximately 2.1 million barrels are idle but could be reconditioned and brought into service, and approximately 250,000 barrels are in displacement oil service. The purchase of these assets resulted in negative goodwill of $23.4 million, which was allocated proportionately to reduce property, plant and equipment of Pacific Terminals.

The financial statements included herein reflect the ownership and results of operations of the assets comprising the Pacific Terminals storage and distribution system for the period July 31, 2003 to September 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") 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 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.

Our PMT gathering and blending system is a proprietary intrastate operation that is not regulated by the CPUC or the Federal Energy Regulatory Commission ("FERC").

The CPUC regulates Pacific Terminals' storage and terminaling operations. The CPUC has authorized Pacific Terminals to establish the terms, conditions and charges for its storage and terminaling services through negotiated contracts with its customers.

AREPI and Frontier pipelines are common carrier pipelines under the jurisdiction of the FERC. AREPI and Frontier pipelines transport crude oil under various cost-based tariffs at published rates, depending on the type and characteristics of the crude oil. The Western Corridor and the Salt Lake City Core systems are common carrier pipelines that ship under cost-based tariffs under the jurisdiction of both the FERC and the Wyoming Public Service Commission ("WPSC").

Pipeline transportation revenue is typically recognized upon delivery of the crude oil to the customer. Storage and terminaling revenue is recognized monthly based on the lease of storage tanks, the use of distribution system assets, and the delivery of related incidental services.

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

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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 derivative instruments related to crude oil inventory are recognized in net income. For the three months ended September 30, 2003, the change in the fair value of PMT's derivative instruments for its marketing activities was immaterial. For the nine months ended September 30, 2003, "crude oil sales, net of purchases" were net of $0.3 million related to changes in the 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 of September 30, 2003, interest rates, as measured by current market quotations for the future periods covered by the interest rate swap agreements, had declined as compared to August and September 2002, when PEG entered into these interest rate swap agreements. This decline resulted in an unrealized loss of $8.2 million on the aggregate interest rate hedge, which is recorded as a liability at September 30, 2003. The $8.2 million liability is shown on the condensed consolidated balance sheet in two components, a current liability of $5.3 million, and a long-term liability of $2.9 million. The unrealized loss reflecting the decline in interest rates from December 31, 2002, is shown in "accumulated other comprehensive income," a component of partners' capital, and not in the condensed consolidated income statement. Should interest rates remain unchanged from the September 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 will be fixed at the all-in interest rate of approximately 7.00%.

By using derivative financial instruments to hedge exposures related to changes in market prices and interest rates, the Partnership exposes itself to market risk and credit risk. Market risk is the risk of loss arising from 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.

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Credit risk is the risk of loss arising from 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 is liable to the Partnership, which creates credit risk for the Partnership. When the fair value of a derivative agreement is negative, the Partnership is liable to the counterparty and, therefore, it does not possess credit risk. As of September 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, as amended. Individual unitholders have different investment bases depending upon the timing and price of acquisition of partnership units. Further, each unitholder's tax accounting, which is partially dependent upon the unitholder's tax position, differs from the accounting followed in the 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 nine months ended September 30, 2003, the denominator of diluted net income per limited partner unit was increased by 192,359 units and 178,359 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 No. 123, net income and earnings per limited partner unit would not have been materially reduced for the three and nine months ended September 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 did not have any impact on the Partnership's financial position or results of operations.

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

2. ACQUISITION

On July 31, 2003, Pacific Terminals completed the acquisition of the black oil storage and pipeline distribution system 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 $9.0 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 fourth quarter of 2003 after the adjustments are finalized. In addition, an estimated $3.0 million of transaction costs and liabilities have been or will be paid or assumed by Pacific Terminals in connection with the acquisition. These assets, which comprise the Pacific Terminals storage and terminaling system, consist of 70 miles of distribution pipelines in active black oil service and 34 storage tanks with a total of approximately 9.0 million barrels of storage capacity. Of this total capacity approximately 6.7 million barrels are in active commercial service, approximately 2.1 million barrels are idle but could be reconditioned and brought into service, and approximately 250,000 barrels are in displacement oil service. The Pacific Terminals storage and terminaling system will be used by the Partnership to serve 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 PEG's $200.0 million revolving credit facility and $10.3 million from cash on hand. On August 25, 2003, the Partnership issued and sold 5,000,000 common units in an underwritten public offering. The Partnership used a portion of the net proceeds from the offering and the related capital contribution of the General Partner of $2.0 million to repay $90.0 million of the $149.0 million borrowing from PEG's revolving credit facility.

The acquisition was accounted for by the purchase method of accounting pursuant to Statement of Financial Accounting Standards No. 141, "Business Combinations" and, accordingly the condensed consolidated statements of income include the results of Pacific Terminals from July 31, 2003. 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. The purchase of the assets resulted in negative goodwill of $23.4 million, which will be allocated proportionately to reduce property, plant and equipment of Pacific Terminals.

3. INVESTMENT IN FRONTIER PIPELINE COMPANY

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

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

Balance Sheets

	September 30, 2003	December 31, 2002
	(in thousands) (unaudited)	
Current assets	$ 2,223	$ 4,481
Property and equipment, net	8,992	9,252
Other assets	1	1
	$ 11,216	$ 13,734
Current liabilities	$ 815	$ 365
Other liabilities	2,194	2,298
Partners' capital	8,207	11,071
	$ 11,216	$ 13,734

Statements of Income

	For the Three Months Ended		For the Nine Months Ended	
	September 30, 2003	September 30, 2002	September 30, 2003	September 30, 2002
	(in thousands) (unaudited)			
Revenue	$ 2,877	$ 2,764	$ 7,415	$ 8,735
Operating expense	(925)	(540)	(2,017)	(1,640)
Depreciation expense	(91)	(107)	(272)	(272)
Operating income	1,861	2,117	5,126	6,823
Rate case litigation settlement				(2,504)
Other income	3	9	9	30
Net income	$ 1,864	$ 2,126	$ 5,135	$ 4,349

4. RELATED PARTY TRANSACTIONS

Our transactions with related parties and affiliates for the three and nine months ended September 30, 2003 and 2002 are as follows:

	For the Three Months Ended		For the Nine Months Ended	
	September 30, 2003	September 30, 2002	September 30, 2003	September 30, 2002
	(in thousands) (unaudited)			
Pipeline transportation revenue:				
The Anschutz Corporation and affiliates(1)	$ 114	$ 280	$ 956	$ 2,132
Operating expense:				
The Anschutz Corporation and affiliates(2)		139		336
General and administrative expense:				
The Anschutz Corporation and affiliates(2)	35	221	126	524

(1) The above amounts include a portion of the annual management fee charged by RMP to Anschutz Wahsatch Gathering System, Inc. ("AWGS"), a wholly owned subsidiary of Anschutz, for reimbursement of time spent by RMP management and for other overhead services related to AWGS activities.

(2) The above amounts exclude reimbursements for insurance paid by Anschutz on behalf of the Partnership. No amounts were paid for reimbursement to Anschutz for the three months ended September 30, 2003. Amounts paid for the nine months ended September 30, 2003 were $0.1 million. Amounts paid for the three and nine months ended September 30, 2002, were $1.4 million and $2.0 million, respectively.

On August 25, 2003, the Partnership issued and sold 5,000,000 common units in an underwritten public offering. The Partnership used a portion of the net proceeds received from the offering to redeem 1,115,000 common units owned by the General Partner for $26.3 million. Following redemption, the 1,115,000 redeemed units were cancelled. In connection with the offering, the General Partner also contributed $2.0 million to the Partnership to maintain its 2% general partner interest.

On August 29, 2003 and September 3, 2003, the underwriters exercised a portion of their over-allotment option and purchased an additional 500,000 common units and 112,100 common units, respectively, from the Partnership. The net proceeds were used to redeem 612,100 common units owned by the General Partner for $14.5 million. Following redemption, the 612,100 redeemed common units were cancelled.

Cash distributions paid to Anschutz on its common units, subordinated units and 2% general partner interest in the Partnership for the three and nine months ended September 30, 2003, were $5.9 million and $17.7 million, respectively. Prior to the Partnership's initial public offering, cash distributions paid to Anschutz for the three and nine months ended September 30, 2002, were $10.0 million and $16.0 million, respectively. Concurrent with the initial public offering in July 2002, PEG paid a distribution of $105.1 million to Anschutz.

Except as described in the paragraph below, there have been no changes to our related party relationships (other than the 2003 amounts associated with such relationships as reflected in the table above) from those described in Note 8 of the Partnership's audited consolidated financial statements included in the Partnership's annual report on Form 10-K for the year ended December 31, 2002.

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 does not have any employees. The General Partner, which is a wholly owned indirect subsidiary of Anschutz, employed approximately 250 individuals at September 30, 2003 who directly supported the operations of the Partnership. All expenses incurred by the General Partner on behalf of the Partnership are charged to the Partnership.

Related party balances at September 30, 2003 and December 31, 2002 were reflected on the balance sheet as follows:

	September 30, 2003	December 31, 2002
	(in thousands)	
	(unaudited)	
Amounts included in accounts receivable:		
The Anschutz Corporation and affiliates	$ 119	$ 521
Amounts included in due to related parties:		
The Anschutz Corporation and affiliates	$	$ 672
Pacific Energy GP, Inc.	285	280
Total	$ 285	$ 952

5. LONG-TERM DEBT

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

	September 30, 2003	December 31, 2002
	(in thousands)	
	(unaudited)	
Senior secured revolving credit facility	$ 59,000	$
Senior secured term loan facility	225,000	225,000
Total	284,000	225,000
Less current portion		
Long-term debt	$ 284,000	$ 225,000

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.

The revolving credit facility is a $200.0 million facility that is available for general partnership purposes, including working capital, letters of credit and distributions to unitholders and to finance future acquisitions. Borrowings under the revolving credit facility are limited by various financial covenants in the credit agreement. The revolving credit facility also has a borrowing sublimit of $45.0 million for working capital, letters of credit and partnership distributions to unitholders. At September 30, 2003, no letters of credit were outstanding under PEG's $200.0 million revolving credit facility.

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.

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.

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 September 30, 2003, PEG and its subsidiaries that are guarantors under the credit agreement were in compliance with all such covenants.

6. PARTNERS' CAPITAL

On August 1, 2003, the Partnership, PEG and certain subsidiaries of PEG filed a universal shelf registration statement on Form S-3 with the SEC to register the issuance and sale, from time to time and in such amounts as is determined by the market conditions and needs of the Partnership, of up to $550.0 million of common units of the Partnership and debt securities of both the Partnership and PEG. The registration statement also registered possible future sales of 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. The SEC declared the registration statement effective on August 8, 2003.

On August 25, 2003, the Partnership issued and sold 5,000,000 common units in an underwritten public offering at a price of $24.66 per common unit before underwriting fees and offering expenses. In addition, the Partnership granted the underwriters an option to purchase up to an additional 750,000 common units to cover over-allotments, if any. Net proceeds received from the offering totaled approximately $117.3 million, after deducting underwriting fees and offering expenses of $6.7 million. The Partnership used the net proceeds from the offering and the related capital contribution of the General Partner of $2.0 million to repay $90.0 million of the $149.0 million of indebtedness outstanding under PEG's revolving credit facility which had been incurred in connection with the acquisition of the Pacific Terminals storage and terminaling system assets, and to redeem 1,115,000 common units owned by the General Partner for $26.3 million, or $23.612 per common unit, which is equal to the net proceeds per common unit the Partnership received in the offering, before offering expenses. Following redemption, the 1,115,000 redeemed common units were cancelled. The remaining net proceeds were retained by the Partnership.

On August 29, 2003 and September 3, 2003, the underwriters exercised a portion of the over-allotment option and purchased an additional 500,000 common units and 112,100 common units, respectively, from the Partnership at a price of $24.66 per common unit to cover over-allotments before underwriting fees and offering expenses. The net proceeds were used to redeem 612,100 common units owned by the General Partner for $14.5 million, or $23.612 per common unit, which is equal to the net proceeds per common unit the Partnership received in the offering, before offering expenses. Following redemption, the 612,100 redeemed common units were cancelled.

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7. SEGMENT INFORMATION

The Partnership's business and operations are organized into two regional operating units: West Coast operations and Rocky Mountain operations. The West Coast operations include PPS, PMT, and Pacific Terminals (for the period from July 31, 2003 to September 30, 2003). Rocky Mountain operations include AREPI, RPL, and RMP (for the period from March 1, 2002). 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 Nine Months Ended

	September 30, 2003(1)(2)	September 30, 2002(2)	September 30, 2003(1)(2)	September 30, 2002(2)
	(in thousands) (unaudited)			
Segment Operating Income				
West Coast Operations:				
Pipeline transportation revenue	$ 13,604	$ 15,281	$ 43,789	$ 48,319
Storage and terminaling revenue	4,710		4,710	
Crude oil sales, net of purchases(3)	7,126	5,606	18,908	16,978
Net revenue before operating expenses	25,440	20,887	67,407	65,297
Expenses:				
Operating	10,830	8,622	27,096	27,541
Transition costs		10		126
Depreciation and amortization	3,529	2,894	9,210	8,387
Total expenses	14,359	11,526	36,306	36,054
Operating income(4)	$ 11,081	$ 9,361	$ 31,101	$ 29,243
Capital expenditures	$ 763	$ 563	$ 1,480	$ 2,102
Identifiable assets	$ 500,808	$ 360,402	$ 500,808	$ 360,402
Rocky Mountain Operations:				
Pipeline transportation revenue	$ 10,678	$ 11,321	$ 30,398	$ 27,092
Expenses:				
Operating	5,800	5,742	16,526	13,098
Transition costs		689	397	2,549
Depreciation and amortization	1,520	1,413	4,225	3,324
Total expenses	7,320	7,844	21,148	18,971
Share of net income of Frontier	414	471	1,141	966
Operating income(4)	$ 3,772	$ 3,948	$ 10,391	$ 9,087
Capital expenditures	$ 366	$ 975	$ 840	$ 1,852
Identifiable assets	$ 143,885	$ 135,656	$ 143,885	$ 135,656

(1) These amounts include two months of operations of the Pacific Terminals storage and terminaling system, which Pacific Terminals acquired on July 31, 2003.

(2) The amounts for the three and nine months ended September 30, 2002 include three and seven months respectively, of operations of the Western Corridor and the Salt Lake City Core systems,

which RMP acquired on March 1, 2002. The amounts for the three and nine months ended September 30, 2003 include three and nine months of operations of the Western Corridor and the Salt Lake City Core systems, respectively.

(3)

The above amounts are net of purchases of $95,614 and $94,042 for the three months ended September 30, 2003 and 2002, respectively. The above amounts are net of purchases of $269,141 and $233,874 for the nine months ended September 30, 2003 and 2002, respectively.

(4)

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

	For the Three Months Ended		For the Nine Months Ended	
	September 30, 2003	September 30, 2002	September 30, 2003	September 30, 2002
	(in thousands) (unaudited)			
Income Statement Reconciliation				
Operating income from above:				
West Coast Operations	$ 11,081	$ 9,361	$ 31,101	$ 29,243
Rocky Mountain Operations	3,772	3,948	10,391	9,087
Total operating income from above	14,853	13,309	41,492	38,330
Less: General and administrative	3,305	1,639	10,289	4,524
Operating income	11,548	11,670	31,203	33,806
Other income	83	133	228	416
Interest income	30	65	132	314
Interest expense	(4,782)	(3,510)	(12,930)	(7,365)
Net income	$ 6,879	$ 8,358	$ 18,633	$ 27,171

8. COMMITMENTS AND CONTINGENCIES

On March 15, 2002, Sinclair Oil Corporation ("Sinclair") filed a complaint with the WPSC alleging that RMP's common stream rules and specifications and RMP's refusal to prohibit certain types of crude oil diluents from the sour crude oil common stream, all in respect of the Big Horn segment of the Western Corridor system, are adverse to Sinclair and the public interest. A hearing on Sinclair's complaint was held by the WPSC in October 2002, and on October 21, 2003, the WPSC issued its written decision, directing RMP to adopt tariff language prohibiting the blending of certain types of crude oil containing diluents with the Wyoming sour crude oil common stream on the Big Horn segment. The effect of this decision is that RMP will not be allowed to continue its practice of commingling Bow River crude oil, a Canadian crude oil that contains diluent, with the Wyoming crude oil that Sinclair claimed were being harmed by the presence of such diluent. As a consequence, RMP will be required to transport the Wyoming crude sour common stream in segregated batches separate from the Western Corridor sour crude oil stream containing diluent. The Partnership has the right to request a re-hearing before the WPSC or to file an appeal of the decision with the Wyoming district court, but no decision has been made in this regard. The full impact of the WPSC's order has not been determined, but if the order stands, RMP will incur additional capital and operating expense to segregate the Wyoming sour crude oils. The WPSC recognized in its decision that the additional cost expected to be incurred by RMP to comply with the order may be recoverable through higher tariffs, subject to a proper showing before the WPSC. The Partnership does not expect this ruling to have a material adverse effect on the Partnership's financial position or results of operations.

The Partnership is subject to numerous federal, state and local laws which regulate the discharge of materials into the environment or that otherwise relate to the protection of the environment. The Partnership currently has an environmental remediation liability of $3.7 million at September 30, 2003 resulting from various acquisitions which was classified in the condensed consolidated balance sheets within "other liabilities." The actual future costs for environmental remediation activities will depend on, among other things, the identification of any additional sites, the determination of the extent of the contamination at each site, the timing and nature of required remedial actions, the technology available and required to meet the various existing legal requirements, the nature and extent of future environmental laws, inflation rates and the determination of the Partnership's liability at multi-party sites, if any, in light of uncertainties with respect to joint and several liability, and the number, participation levels and financial viability of other potentially responsible parties.

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

9. SUBSEQUENT EVENT

On October 20, 2003, the Partnership declared a cash distribution of $0.4875 per limited partner unit, payable on November 14, 2003 to unitholders of record as of October 31, 2003.

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

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

Forward-Looking Statements

The information in this quarterly report on Form 10-Q contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, and Section 21E of the Securities Exchange Act of 1934. These forward-looking statements are identified as any statements that do not relate strictly to historical or current facts, including statements that use terms such as "anticipate," "assume," "believe," "estimate," "expect," "forecast," "intend," "plan," "position," "predict," "project," or "strategy" or the negative connotation or other variations of such terms or other similar terminology. In particular, statements, express or implied, regarding our future results of operations or our ability to generate sales, income or cash flow or to make distributions to unitholders are forward-looking statements. Forward-looking statements are not guarantees of performance. Such statements are based on management's current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve risks and uncertainties. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or predict.

We caution you that the forward-looking statements in this quarterly report on Form 10-Q are subject to all of the risks and uncertainties, many of which are beyond our control, incident to gathering, transporting, storing, and distributing crude oil. For a more detailed description of these and other factors that may affect the forward-looking statements, please read "Risk Factors" contained in our universal shelf registration statement on Form S-3 (SEC File No.: 333-107609), filed August 1, 2003 and declared effective by the SEC on August 8, 2003. The risk factors could cause our actual results to differ materially from those contained in any forward-looking statement. You should not put undue reliance on these forward-looking statements. We disclaim any obligation to announce publicly the result of any revision to any of the forward-looking statements to reflect future events or developments.

Introduction

The following discussion of the financial condition and results of operations of Pacific Energy Partners, L.P., the successor to Pacific Energy (Predecessor) (as defined below) should be read together with the condensed consolidated financial statements and the notes thereto set forth elsewhere in this report. The discussion set forth in this section pertains to the unaudited condensed consolidated balance sheet, statements of income and statements of cash flows of, as well as equity investment in, the Partnership and its 100% ownership interest in Pacific Energy

Group LLC ("PEG"), whose subsidiaries consist of: (i) Pacific Pipeline System LLC ("PPS"), owner of Line 2000 and the Line 63 system, (ii) Pacific Marketing and Transportation LLC ("PMT"), owner of the PMT gathering and blending facilities, (iii) Pacific Terminals LLC ("Pacific Terminals"), owner of the Pacific Terminals storage and terminaling system assets acquired from Edison Pipeline and Terminal Company, a division of Southern California Edison Company, on July 31, 2003, (iv) Rocky Mountain Pipeline System LLC ("RMP"), owner of the Western Corridor and the Salt Lake City Core systems, (v) Anschutz Ranch East Pipeline LLC ("AREPI"), owner of AREPI pipeline, and (vi) 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 nine months ended September 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, Pacific Terminals, RMP, AREPI and RPL for the three and nine

months ended September 30, 2003, are presented on a consolidated basis as successor to the Predecessor.

The financial data included herein reflects the ownership and results of operations of the assets comprising the Pacific Terminals storage and terminaling system for the period from July 31, 2003 to September 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 units representing limited partner interests.

On August 25, 2003, we issued and sold 5,000,000 common units in an underwritten public offering at a price of $24.66 per common unit before underwriting fees and offering expenses. In addition, we granted the underwriters an option to purchase up to an additional 750,000 common units to cover over-allotments, if any. Net proceeds received from the offering totaled approximately $117.3 million, after deducting underwriting fees and offering expenses of $6.7 million. We used the net proceeds from the offering and the related capital contribution of our general partner of $2.0 million to repay $90.0 million of the $149.0 million of indebtedness outstanding under PEG's revolving credit facility which had been incurred in connection with the acquisition of the Pacific Terminals storage and terminaling system assets and to redeem 1,115,000 common units owned by our general partner for $26.3 million, or $23.612 per common unit, which is equal to the net proceeds per common unit the Partnership received in the offering, before offering expenses. Following redemption, the 1,115,000 redeemed common units were cancelled. The remaining net proceeds were retained by us.

On August 29, 2003 and September 3, 2003, the underwriters exercised a portion of the over-allotment option and purchased an additional 500,000 common units and 112,100 common units, respectively, from us at a price of $24.66 per common unit to cover over-allotments before underwriting fees and offering expenses. The net proceeds were used to redeem 612,100 common units owned by the General Partner for $14.5 million, or $23.612 per common unit, which is equal to the net proceeds per common unit we received in the offering, before offering expenses. Following redemption, the 612,100 redeemed common units were cancelled.

We are engaged principally in the business of gathering, transporting, storing and distributing crude oil in California and the Rocky Mountain region. We conduct our business through two regional operating units: West Coast operations and Rocky Mountain operations. Our West Coast operations consist of transporting crude oil produced in California's San Joaquin Valley and the California Outer Continental Shelf to refineries and terminal facilities in the Los Angeles Basin and in Bakersfield 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 purchase, gathering and blending of crude oil that is generally delivered into our Line 63 system for resale to Los Angeles Basin refiners. In addition, on July 31, 2003, Pacific Terminals completed the acquisition of the black oil storage and terminaling system assets of Edison Pipeline and Terminal Company, a division of Southern California Edison Company. These assets comprise our Pacific Terminals storage and terminaling system located in the Los Angeles Basin. 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 and by leasing capacity in our storage facilities. We also buy, blend and sell crude oil, activities that are complementary to our pipeline transportation business.

The tariff rates charged on PPS's pipelines are regulated by the California Public Utilities Commission ("CPUC"). 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 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.

Our PMT gathering and blending system is a proprietary intrastate operation that is not regulated by the CPUC or the Federal Energy Regulatory Commission ("FERC").

The rates charged by Pacific Terminals for its storage and terminaling services are regulated by the CPUC. The CPUC has authorized Pacific Terminals to establish the terms, conditions and charges for its storage and terminaling services through negotiated contracts with its customers.

The tariff rates charged on AREPI and Frontier pipelines are regulated by the FERC. AREPI and Frontier pipelines transport crude oil under various cost-based tariffs at published rates, depending on the type and characteristics of the crude oil. The tariff rates charged on the Western Corridor and the Salt Lake City Core systems are regulated by both the FERC and the Wyoming Public Service Commission. The Western Corridor and the Salt Lake City Core systems transport crude oil under various cost-based tariffs at published rates, although competitive forces may limit such rates.

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 our universal shelf registration statement on Form S-3 (SEC File No.: 333-107609), filed August 1, 2003, and declared effective by the Securities and Exchange Commission ("SEC") on August 8, 2003, and our annual report on Form 10-K for the year ended December 31, 2002.

Results of Operations

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

	For the Three Months Ended		For the Nine Months Ended	
	September 30, 2003(1)(2)	September 30, 2002(2)	September 30, 2003(1)(2)	September 30, 2002(2)
	(in thousands) (unaudited)			
Segment Operating Income				
West Coast Operations:				
Pipeline transportation revenue	$ 13,604	$ 15,281	$ 43,789	$ 48,319
Storage and terminaling revenue	4,710		4,710	
Crude oil sales, net of purchases(3)	7,126	5,606	18,908	16,978
Net revenue before operating expenses	25,440	20,887	67,407	65,297
Expenses:				
Operating	10,830	8,622	27,096	27,541
Transition costs		10		126
Depreciation and amortization	3,529	2,894	9,210	8,387
Total expenses	14,359	11,526	36,306	36,054
Operating income(4)	$ 11,081	$ 9,361	$ 31,101	$ 29,243
Operating Data:				
Line 2000 and Line 63 pipeline throughput (bpd)(5)	146.4	153.7	154.0	165.2
Rocky Mountain Operations:				
Pipeline transportation revenue	$ 10,678	$ 11,321	$ 30,398	$ 27,092
Expenses:				
Operating	5,800	5,742	16,526	13,098
Transition costs		689	397	2,549
Depreciation and amortization	1,520	1,413	4,225	3,324
Total expenses	7,320	7,844	21,148	18,971
Share of net income of Frontier	414	471	1,141	966
Operating income(4)	$ 3,772	$ 3,948	$ 10,391	$ 9,087
Operating Data:				
Salt Lake City Core system throughput (bpd)(5)(6)	68.3	74.1	65.9	71.7
Western Corridor system throughput (bpd)(5)(6)	17.7	13.4	16.2	15.1
AREPI pipeline throughput (bpd)(5)	47.8	46.7	41.6	48.7
Frontier pipeline throughput (bpd)(5)(7)	47.9	46.6	41.5	44.2

(1) These amounts include two months of operations of the Pacific Terminals storage and terminaling system, which Pacific Terminals acquired on July 31, 2003.

(2)
The amounts for the three and nine months ended September 30, 2002 include three and seven months respectively, of operations of the Western Corridor and the Salt Lake City Core systems,

which RMP acquired on March 1, 2002. The amounts for the three and nine months ended September 30, 2003 include three and nine months of operations of the Western Corridor and the Salt Lake City Core systems, respectively.

(3)
The above amounts are net of purchases of $95,614 and $94,042 for the three months ended September 30, 2003 and 2002, respectively. The above amounts are net of purchases of $269,141 and $233,874 for the nine months ended September 30, 2003 and 2002, respectively.

(4)
The following is a reconciliation of operating income as stated above to the statements of income:

	For the Three Months Ended		For the Nine Months Ended	
	September 30, 2003(1)(2)	**September 30, 2002(2)**	**September 30, 2003(1)(2)**	**September 30, 2002(2)**
	(in thousands) (unaudited)			
Income Statement Reconciliation				
Operating income from above:				
West Coast Operations	$ 11,081	$ 9,361	$ 31,101	$ 29,243
Rocky Mountain Operations	3,772	3,948	10,391	9,087
Total operating income from above	14,853	13,309	41,492	38,330
Less: General and administrative	3,305	1,639	10,289	4,524
Operating income	11,548	11,670	31,203	33,806
Other income	83	133	228	416
Interest income	30	65	132	314
Interest expense	(4,782)	(3,510)	(12,930)	(7,365)
Net income	$ 6,879	$ 8,358	$ 18,633	$ 27,171

(5)
bpd is barrels per day.

(6)
This amount represents throughput for the period of March 1, 2002 to September 30, 2002 and the nine months ended September 30, 2003, as this system was acquired on March 1, 2002.

(7)
This figure represents 100% of the throughput on Frontier pipeline.

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

Summary

Net Income. Consolidated net income totaled $6.9 million for the three months ended September 30, 2003, compared to $8.4 million for the corresponding period in 2002, a decrease of $1.5 million, or 18%. Net income per limited partner unit for the three months ended September 30, 2003 was $0.30, compared to $0.25 for the period from our initial public offering on July 26, 2002 to September 30, 2002.

Net income for the three months ended September 30, 2003, includes two months of operations of the Pacific Terminals storage and terminaling system, which Pacific Terminals acquired on July 31, 2003.

The decrease in net income resulted from lower West Coast pipeline throughput, increased general and administrative expense and increased interest expense. These factors were partially offset by the contribution to net income of Pacific Terminals in the current quarter, an increased contribution from our gathering and blending operations and elimination of transition costs incurred in the corresponding period in 2002 in connection with our 2002 Rocky Mountain acquisitions. General and administrative expense increased as a result of our significant growth in 2002 and becoming a publicly traded master limited partnership. The increased interest expense was the result of higher cost fixed rate debt in our post initial public offering capital structure compared to the floating-rate debt for most of the corresponding period in 2002, as well as the cost associated with the additional debt incurred in connection with the acquisition of the Pacific Terminals storage and terminaling system assets on July 31, 2003.

Segment Information

West Coast Operations. Operating income for our West Coast operations totaled $11.1 million for the three months ended September 30, 2003, compared to $9.4 million for the corresponding period in 2002, an increase of $1.7 million, or 18%.

This increase was primarily due to the acquisition of the Pacific Terminals storage and terminaling system assets on July 31, 2003. In addition, for the three months ended September 30, 2003, we experienced higher margins on our gathering and blending operations, compared to the corresponding period in 2002.

This increase in income was partially offset by a reduction in pipeline transportation revenue of $1.7 million as average daily pipeline throughput decreased to 146,400 barrels per day for the three months ended September 30, 2003, compared to 153,700 barrels per day for the corresponding period in 2002. California Outer Continental Shelf ("OCS") throughput to the Los Angeles Basin was lower during the three months ended September 30, 2003, as compared to the corresponding period in 2002, primarily due to maintenance downtime at off-shore production facilities as well as expected production decline. In addition, refinery maintenance at various refineries and increased demand for light crude oil at refineries in Bakersfield reduced throughput to the Los Angeles Basin.

Rocky Mountain Operations. Operating income for our Rocky Mountain operations totaled $3.8 million for the three months ended September 30, 2003, compared to $3.9 million for the corresponding period in 2002, a decrease of $0.1 million, or 3%.

This decrease was mainly due to a decline in trucking revenue, which is included in pipeline transportation revenue. Trucking services are incidental to our pipeline operations. Although average daily pipeline throughput on the Salt Lake City Core system decreased to 68,300 barrels per day for the three months ended September 30, 2003, compared to 74,100 barrels per day for the corresponding period in 2002, the impact of this decline in throughput on revenue was largely offset by an increase in throughput of 4,300 barrels per day on the Western Corridor system. This decrease in revenue was partially offset by the elimination of transition costs of $0.7 million for the three months ended September 30, 2003, compared to the corresponding period in 2002. These transition costs consisted of payments to the seller of the Western Corridor and the Salt Lake City Core systems for certain interim operations support and financial systems services.

Statement of Income Discussion and Analysis

Pipeline Transportation Revenue. Consolidated pipeline transportation revenue totaled $24.3 million for the three months ended September 30, 2003, compared to $26.6 million for the corresponding period in 2002, a decrease of $2.3 million, or 9%. This decrease was in part attributable to our West Coast operations, where pipeline transportation revenue decreased by $1.7 million compared to the corresponding period in 2002 due to a decline in throughput. Rocky Mountain pipeline transportation revenue for the three months ended September 30, 2003 also decreased by $0.6 million compared to the corresponding period in 2002, due to a decline in trucking revenue. Please read " Segment Information."

Storage and Terminaling Revenue. The acquisition of the Pacific Terminals storage and terminaling system assets on July 31, 2003, resulted in storage and terminaling revenue of $4.7 million for the three months ended September 30, 2003.

Crude Oil Sales, net. The PMT gathering and blending system generated crude oil sales, net of purchases, for the three months ended September 30, 2003, of $7.1 million on total sales of $102.7 million, as compared to crude oil sales, net of purchases, of $5.6 million on total sales of $99.6 million for the corresponding period in 2002. The increase in total sales for the 2003 period was the result of higher crude oil prices. We also realized higher margins on our gathering and blending operations for the 2003 period. This increase in margins was partially offset by an increase in transportation and blending costs included in operating expenses. We consider this activity to be ancillary to our pipeline transportation operations.

Operating Expense. Consolidated operating expense totaled $16.6 million for the three months ended September 30, 2003, compared to $14.4 million for the corresponding period in 2002, an increase of $2.2 million, or 15%. Consolidated operating expense for the three months ended September 30, 2003, includes two months of operating expense for Pacific Terminals, which commenced operations on July 31, 2003. Pipeline field operating expense was less in the 2003 period.

Transition Costs. No transition costs were incurred for the three months ended September 30, 2003. Consolidated transition costs of $0.7 million for the three months ended September 30, 2002 consisted of payments to the seller of the Western Corridor and the Salt Lake City Core systems for certain interim operations support and financial systems services.

General and Administrative Expense. Consolidated general and administrative expense was $3.3 million for the three months ended September 30, 2003, compared to $1.6 million for the corresponding period in 2002, an increase of $1.7 million, or 106%. This increase includes $0.7 million of expense for long-term incentive plan awards made in December 2002 and in 2003, with the balance attributable to additional costs incurred as a result of the acquisition of the Western Corridor and the Salt Lake City Core systems, and increased costs associated with our growth as a publicly traded master limited partnership.

Depreciation and Amortization Expense. Consolidated depreciation and amortization expense was $5.0 million for the three months ended September 30, 2003, compared to $4.3 million for the corresponding period in 2002, an increase of $0.7 million, or 16%. This increase includes $0.6 million for depreciation of the Pacific Terminals storage and terminaling system assets, acquired on July 31, 2003.

Interest Expense. Consolidated interest expense was $4.8 million for the three months ended September 30, 2003, compared to $3.5 million for the corresponding period in 2002, an increase of $1.3 million, or 37%. Of this increase, $0.6 million was attributable to an increase in borrowings for the period to finance the acquisition of the Pacific Terminals storage and terminaling system assets on July 31, 2003. The remaining increase was due to an increase in the interest rate on outstanding borrowings during the three months ended September 30, 2003. Our interest rate on outstanding borrowings averaged 6.5% for the three months ended September 30, 2003, as compared to 5.9% during the corresponding period in 2002, reflecting the cost of interest rate swap agreements in which we fixed the interest rates on $170.0 million of our post initial public offering debt. Additionally, in the third quarter of 2003, the applicable margin on the interest rates applicable to PEG's revolving credit facility increased, pursuant to the terms of that facility, by 0.5%, following the acquisition of the Pacific

Terminal storage and terminaling system assets. This increased margin was in effect until August 25, 2003, the closing date of our offering of 5,000,000 additional common units, when $90.0 million of the net proceeds was used to reduce outstanding indebtedness.

Share of Net Income of Frontier. Our share of net income of Frontier was $0.4 million for the three months ended September 30, 2003, compared to $0.5 million for the corresponding period in 2002, a decrease of $0.1 million, or 20%.

Nine Months Ended September 30, 2003 Compared to Nine Months Ended September 30, 2002

Summary

Net Income. Consolidated net income totaled $18.6 million for the nine months ended September 30, 2003, compared to $27.2 million for the corresponding period in 2002, a decrease of $8.6 million, or 32%. Basic net income per limited partner unit for the nine months ended September 30, 2003, was $0.85 per limited partner unit.

Net income for the nine months ended September 30, 2003, includes two months of operation of the Pacific Terminals storage and terminaling system assets that Pacific Terminals acquired on July 31, 2003. Net income for the nine months ended September 30, 2002, includes the results of the Western Corridor and the Salt Lake City Core systems for seven months following their acquisition on March 1, 2002.

The decrease in net income was the result of lower West Coast pipeline throughput, increased general and administrative expense and increased interest expense. These factors were partially offset by the contribution to net income of the Pacific Terminals storage and terminaling system since its acquisition on July 31, 2003 and a full nine months of operation of the Western Corridor and the Salt Lake City Core systems acquired on March 1, 2002. In addition, in 2003 we experienced lower West Coast operating expense and elimination of transition costs and fees for support services that had been rendered by the seller of the Western Corridor and the Salt Lake City Core systems in the corresponding period in 2002. General and administrative expense increased in the 2003 period as a result of our significant growth in 2002 and becoming a publicly traded master limited partnership. The increased interest expense was the result of higher cost fixed rate debt in our post initial public offering capital structure compared to the floating-rate debt for most of the corresponding period in 2002, as well as the cost associated with the additional debt incurred in connection with the acquisition of the Pacific Terminals storage and terminaling system assets on July 31, 2003.

Segment Information

West Coast Operations. Operating income for our West Coast operations totaled $31.1 million for the nine months ended September 30, 2003, compared to $29.2 million for the corresponding period in 2002, an increase of $1.9 million or 7%.

This increase was primarily due to the acquisition of the Pacific Terminals storage and terminaling system assets on July 31, 2003, and an increase in margins on our gathering and blending operations. This increase was offset by a reduction in pipeline transportation revenue of $4.5 million as average daily pipeline throughput decreased to 154,000 barrels per day for the nine months ended September 30, 2003, compared to 165,200 barrels per day for the corresponding period in 2002. OCS throughput to the Los Angeles Basin was lower during the nine months ended September 30, 2003, as compared to the corresponding period in 2002, primarily due to maintenance downtime at both on-shore processing and off-shore production facilities, as well as expected production decline. In addition, refinery maintenance at various refineries and increased mid-barrel crude oil ("MBCO") demand in San Francisco reduced MBCO throughput to the Los Angeles Basin. Increased demand for light crude oil at refineries in Bakersfield also reduced throughput to the Los Angeles Basin. Our crude

oil sales, net of purchases, increased $1.9 million for the nine months ended September 30, 2003, compared to the corresponding period in 2002, as we experienced higher margins on our gathering and blending operations.

Rocky Mountain Operations. Operating income for our Rocky Mountain operations totaled $10.4 million for the nine months ended September 30, 2003, compared to $9.1 million for the corresponding period in 2002, an increase of $1.3 million, or 14%.

This increase was primarily due to a full nine months of operations of the Western Corridor and the Salt Lake City Core systems, which were acquired on March 1, 2002. However, average daily pipeline throughput was lower during the nine months ended September 30, 2003, as compared to the period of March 1, 2002 to September 30, 2002, due to refinery downtime that reduced demand for crude oil at Salt Lake City refineries, our precautionary reduction in line pressure that reduced throughput on a Salt Lake City Core system pipeline pending pipeline integrity testing (which was completed along with the restoration of normal pressure in the second quarter of 2003), and from lesser quantities of crude oil being available to shippers in some areas served by our Rocky Mountain pipelines.

Statement of Income Discussion and Analysis

Pipeline Transportation Revenue. Consolidated pipeline transportation revenue totaled $74.2 million for the nine months ended September 30, 2003, compared to $75.4 million for the corresponding period in 2002, a decrease of $1.2 million, or 2%.

Rocky Mountain pipeline transportation revenue increased by $3.3 million compared to the corresponding period in 2002 due to revenue generated by the Western Corridor and the Salt Lake City Core systems for nine months in 2003 compared to seven months in the 2002 period following their acquisition on March 1, 2002. The increase in Rocky Mountain pipeline transportation revenue for the nine months ended September 30, 2003 was more than offset by a decrease in West Coast pipeline transportation revenue of $4.5 million due to lower average daily throughput as noted above.

Storage and Terminaling Revenue. The acquisition of the Pacific Terminals storage and terminaling system assets on July 31, 2003, resulted in storage and terminaling revenue of $4.7 million for the nine months ended September 2003.

Crude Oil Sales, net. The PMT gathering and blending system generated crude oil sales, net of purchases, for the nine months ended September 30, 2003, of $18.9 million on total sales of $288.0 million, compared to crude oil sales, net of purchases, of $17.0 million on total sales of $250.9 million for the corresponding period in 2002. The increase in total sales for the 2003 period was the result of higher crude oil prices. We also realized higher margins on our gathering and blending operations for the 2003 period. This increase in margins was partially offset by an increase in transportation and blending costs included in operating expense. We consider this activity to be ancillary to our pipeline transportation operations.

Operating Expense. Consolidated operating expense totaled $43.6 million for the nine months ended September 30, 2003, compared to $40.6 million for the corresponding period in 2002, an increase of $3.0 million, or 7%. Consolidated operating expense for the nine months ended September 30, 2003, includes two months of operating expense for Pacific Terminals, which commenced operations on July 31, 2003. The increase in operating expense was related primarily to the acquisitions of the Western Corridor and the Salt Lake City Core systems and the Pacific Terminals storage and terminaling system assets.

Operating expense for our Rocky Mountain operations increased by $3.4 million due to a full nine months of operation of the Western Corridor and the Salt Lake City Core systems compared to seven

months of operation for the corresponding period in 2002. For the nine months ended September 30, 2003, we incurred two months of operating expense relating to the Pacific Terminals storage and terminaling system assets, which were acquired on July 31, 2003. These increases were partially offset by $2.2 million in transition cost savings as discussed below. Operating expense for our West Coast operations decreased by $0.4 million primarily due to decreased right-of-way expense resulting from the relinquishment of certain unused rights-of-way and due to lower field operating expense. We also experienced higher insurance expense and property tax expense for the nine months ended September 30, 2003, compared to the corresponding period in 2002, for both our West Coast and Rocky Mountain operations.

Transition Costs. Consolidated transition costs were $0.4 million for the nine months ended September 30, 2003, compared to $2.7 million for the corresponding period in 2002, a decrease of $2.3 million, or 85%. Transition costs in 2003 consisted only of employee transition bonus payments, whereas transition costs in 2002 consisted of payments to the seller of the Western Corridor and the Salt Lake City Core systems for certain interim operations support, financial systems services and employee transition bonuses.

General and Administrative Expense. Consolidated general and administrative expense was $10.3 million for the nine months ended September 30, 2003, compared to $4.5 million for the corresponding period in 2002, an increase of $5.8 million, or 129%. This increase includes $2.6 million of expense for long-term incentive awards made in December 2002 and in 2003, with the balance attributable to additional costs incurred as a result of the acquisition of the Western Corridor and the Salt Lake City Core systems, and increased costs associated with our growth as a publicly traded master limited partnership.

Depreciation and Amortization Expense. Consolidated depreciation and amortization expense was $13.4 million for the nine months ended September 30, 2003, compared to $11.7 million for the corresponding period in 2002, an increase of $1.7 million, or 15%. This increase includes $0.9 million for nine months of depreciation of the Western Corridor and the Salt Lake City Core systems in the 2003 period, compared to seven months in the 2002 period following their acquisition on March 1, 2002, and $0.6 million for depreciation of the Pacific Terminals storage and terminaling system assets, acquired on July 31, 2003

Interest Expense. Consolidated interest expense was $12.9 million for the nine months ended September 30, 2003, compared to $7.4 million for the corresponding period in 2002, an increase of $5.5 million, or 74%. Of this increase, $0.6 million was attributable to an increase in borrowings during the 2003 period to finance the acquisition of the Pacific Terminals storage and terminaling system assets on July 31, 2003. The remaining increase was mostly due to an increase in the interest rate on outstanding borrowings during the nine months ended September 30, 2003. Our interest rate on outstanding borrowings averaged 6.9% for the nine months ended September 30, 2003, as compared to 4.1% during the corresponding period in 2002, reflecting our interest rate swap agreements in which we fixed the interest rates on $170.0 million of our post initial public offering debt. Additionally, in the third quarter of 2003, the applicable margin on our interest rates increased by 0.5%, following the acquisition of the Pacific Terminal storage and terminaling system assets. This increased margin was in effect until August 25, 2003, the closing date of our offering of 5,000,000 additional common units. We used a portion of the net proceeds from the offering and the related capital contribution of our general partner of $2.0 million to repay $90.0 million of the $149.0 million borrowing from PEG's revolving credit facility.

Share of Net Income of Frontier. Our share of net income of Frontier was $1.1 million for the nine months ended September 30, 2003, compared to $1.0 million for the corresponding period in 2002, an increase of $0.1 million, or 10%.

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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 from 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 crude oil throughput and 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 and storage facilities. 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 October 20, 2003, the Partnership declared a cash distribution of $0.4875 per limited partner unit, payable on November 14, 2003 to unitholders of record as of October 31, 2003.

Operating, Investing and Financing Activities

Net cash provided by operating activities was $33.4 million for the nine months ended September 30, 2003, compared to $28.7 million for the corresponding period in 2002, an increase of $4.7 million, or 16%. 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 $162.1 million for the nine months ended September 30, 2003 compared to $99.2 million for the corresponding period in 2002. Net cash used in investing activities for the nine months ended September 30, 2003, includes $159.9 million paid to date for the acquisition of the Pacific Terminals storage and terminaling system assets on July 31, 2003. The 2002 period included the acquisition of the Western Corridor and the Salt Lake City Core systems on March 1, 2002. Capital expenditures were $2.3 million for the nine months ended September 30, 2003, of which $1.3 million related to maintenance capital projects, $0.9 million related to expansion projects, and $0.1 million related to transition projects. Capital expenditures were $4.0 million for the nine months ended September 30, 2002, of which $1.8 million related to maintenance capital projects, $0.6 million related to expansion projects and $1.6 million related to transition projects.

Net cash provided by financing activities for the nine months ended September 30, 2003 was $122.2 million and includes proceeds of $149.0 million under the revolving credit facility which were used to fund, in part, the acquisition of the Pacific Terminals storage and terminaling system assets on July 31, 2003. In August and September 2003, we also issued and sold additional common units for gross proceeds of $138.4 million. The proceeds from the offering and related capital contribution from our general partner of $2.0 million were used repay $90.0 million of debt under the revolving credit facility, redeem 1.7 million outstanding common units totaling $40.8 million held by our general partner, and pay underwriting fees and offering expenses of $6.7 million. Following redemption, the 1.7 million redeemed common units were cancelled. Our distributions to limited partners and our general partner for the nine months ended September 30, 2003 were $29.7 million.

Net cash provided by financing activities for the nine months ended September 30, 2002 was $81.9 million and includes, in connection with our initial public offering, proceeds of $225.0 million from the term loan facility which were used to repay debt of $114.6 million and to fund distributions of $105.1 million to our general partner. Also, in connection with our initial public offering in July 2002, proceeds of $167.7 million from the issuance of common units were used to pay underwriting discounts, professional fees and other offering costs of $17.1 million and to repay $151.3 million in debt.

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Contributions of members and distributions to members prior to the initial public offering were $8.8 million and $16.0 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 $2.4 million, expansion capital expenditures of $8.8 million and transitional capital expenditures of $0.3 million for 2003.

We have been evaluating the feasibility of developing a deep-water bulk liquid petroleum import facility at the Port of Los Angeles and in June 2003 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 fourth quarter of 2003, we expect to complete the determination of the feasibility of the project.

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 $0.8 million and $0.6 million during the three month periods ended September 30, 2003 and September 30, 2002, respectively. Right-of-way payments were $2.2 million and $2.6 million during the nine months ended September 30, 2003 and 2002, respectively.

Credit Facilities

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

	September 30, 2003	December 31, 2002
	(in thousands)	
	(unaudited)	
Senior secured revolving credit facility	$ 59,000	$
Senior secured term loan facility	225,000	225,000
Total	284,000	225,000
Less current portion		
Long-term debt	$ 284,000	$ 225,000

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 our 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.

On July 31, 2003, pursuant to PEG's credit agreement, we filed applications with the CPUC 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. The applications to the CPUC also sought, in the alternative, authority for PPS and Pacific Terminals to borrow $176.0 million and $167.0 million, respectively, from PEG, on terms generally comparable to those applicable under the revolving credit and term loan facilities. On October 31, 2003, the CPUC issued its decision on the PPS application, rejecting PPS's request to guarantee a portion of PEG's obligations to its lenders, but granting the alternative request for approval for PPS to borrow $176 million from PEG on a long term basis. In light of this ruling and certain requests for information submitted to us by the Administrative Law Judge reviewing the Pacific Terminals application, we intend to amend the Pacific Terminals application so as to reduce the amount of indebtedness to PEG for which approval is being sought and to seek approval for such indebtedness to PEG to be secured by certain assets of Pacific Terminals. Any notes evidencing long-term indebtedness from PPS or Pacific Terminals to PEG will be pledged by PEG to its lenders as additional security under the credit agreement.

The revolving credit facility is a $200.0 million facility that is available for general partnership purposes, including working capital, letters of credit, and distributions to unitholders, and to finance future acquisitions. Borrowings under the revolving credit facility are limited by various financial covenants. The revolving credit facility also has a borrowing sublimit of $45.0 million for working capital, letters of credit and partnership distributions to unitholders. At September 30, 2003, there were no letters of credit outstanding under PEG's $200.0 million revolving credit facility.

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 and term loan facilities at any time, without premium or penalty. 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

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asset sales not sold in the ordinary course of business and the net proceeds of new senior secured debt offerings, subject to certain exceptions.

Indebtedness under the facilities bears interest at the Partnership's option, at either (i) the base rate, which is equal to the higher of the prime rate as announced by 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.

PEG will incur a per annum commitment fee 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%. 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.

Universal Shelf Registration Statement

On August 1, 2003, the Partnership, PEG and certain subsidiaries of PEG filed a universal shelf registration statement on Form S-3 with the SEC to register the issuance and sale, from time to time and in such amounts as is determined by the market conditions and our needs, of up to $550.0 million of common units of the Partnership and debt securities of both the Partnership and PEG. The registration statement also registered possible future sales of up to 1,865,000 common units held by our general partner, which acquired these common units as partial consideration for its contribution to the Partnership of assets and liabilities in connection with our initial public offering. The SEC declared the registration statement effective on August 8, 2003.

On August 25, 2003, we issued and sold 5,000,000 common units in an underwritten public offering at a price of $24.66 per common unit before underwriting fees and offering expenses. In addition, we granted the underwriters an option to purchase up to an additional 750,000 common units to cover over-allotments, if any. Net proceeds received from the offering totaled approximately $117.3 million, after deducting underwriting fees and offering expenses of $6.7 million. We used the net proceeds from the offering and the related capital contribution of our general partner of $2.0 million to repay $90.0 million of the $149.0 million of indebtedness outstanding under PEG's revolving credit facility, which had been incurred in connection with the acquisition of the Pacific Terminals storage and terminaling system assets and to redeem 1,115,000 common units owned by our general partner for $26.3 million, or $23.612 per common unit, which is equal to the net proceeds per common unit we received in the offering, before offering expenses. Following redemption, the 1,115,000 redeemed common units were cancelled. We retained the remaining net proceeds.

On August 29, 2003 and September 3, 2003, the underwriters exercised a portion of the over-allotment option and purchased an additional 500,000 common units and 112,100 common units, respectively, from us at a price of $24.66 per common unit to cover over-allotments before underwriting fees and offering expenses. The net proceeds were used to redeem 612,100 common units owned by

our general partner for $14.5 million, or $23.612 per common unit, which is the price per unit equal to the net proceeds per common unit we received in the offering, before offering expenses. Following redemption, the 612,100 redeemed common units were cancelled.

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 derivative instruments are recognized in net income. For the three months ended September 30, 2003, the change in the fair value of PMT's derivative instruments for its marketing activities was immaterial. For the nine months ended September 30, 2003, "crude oil sales, net of purchases" were net of $0.3 million related to changes in the 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 of September 30, 2003, interest rates, as measured by current market quotations for the future periods covered by the interest rate swap agreements, had declined as compared to August and September 2002, when PEG entered into these interest rate swap agreements. This decline resulted in an unrealized loss of $8.2 million on the aggregate interest rate hedge, which is recorded as a liability at September 30, 2003. The $8.2 million liability is shown on the condensed consolidated balance sheet in two components, a current liability of $5.3 million, and a long-term liability of $2.9 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 September 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 will be fixed at the all-in interest rate of approximately 7.00%.

We are subject to risks resulting from interest rate fluctuations as interest on the remaining $55.0 million outstanding under our term loan facility and $59.0 million outstanding under our revolving credit facility are based on variable rates. If the LIBOR rate were to increase 1.00% in

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as compared to the rate at September 30, 2003, our interest expense for 2003 would increase $1.1 million based on the outstanding debt at September 30, 2003, which has not been hedged.

ITEM 4. Controls and Procedures

Disclosure Controls and Procedures

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

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

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

Internal Control Over Financial Reporting

There has not been any change in our internal control over financial reporting that occurred during our quarterly period ended September 30, 2003 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. Legal Proceedings

See discussion of legal proceedings in "Note 8 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:

Description

Exhibit Number	
* Exhibit 31.1	Certification of Principal Executive Officer of Pacific Energy GP, Inc., General Partner of Pacific Energy Partners, L.P., as required by Rule 13a-14(a) of the Securities Exchange Act of 1934
* Exhibit 31.2	Certification of Principal Financial Officer of Pacific Energy GP, Inc., General Partner of Pacific Energy Partners, L.P., as required by Rule 13a-14(a) of the Securities Exchange Act of 1934
Exhibit 32.1	Certification of Chief Executive Officer of Pacific Energy GP, Inc., General Partner of Pacific Energy Partners, L.P., pursuant to 18 U.S.C. §1350
Exhibit 32.2	Certification of Chief Financial Officer of Pacific Energy GP, Inc., General Partner of Pacific Energy Partners, L.P., pursuant to 18 U.S.C. §1350

*

Filed herewith.

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

(b)

Reports on Form 8-K

The Partnership filed the following reports on Forms 8-K and 8-K/A during the three months ended September 30, 2003:

Date of Event Reported	Item(s) Reported	Description
July 10, 2003	Items 7 & 9*	Filed in connection with the Partnership's press release on July 10, 2003 announcing the pending purchase of the assets comprising the Pacific Terminals storage and terminaling system from Southern California Edison Company was approved by the CPUC.
July 30, 2003	Items 7, 9 & 12*	Filed in connection with the Partnership's 2nd quarter 2003 earnings release on July 30, 2003.
July 31, 2003	Items 2 & 7	Filed in connection with the Partnership's press release on July 31, 2003 announcing the closing of the acquisition of the assets comprising the Pacific Terminals storage and terminaling system and an expected cash distribution increase.
July 31, 2003	Items 7 & 9*	Filed in connection with the Partnership's closing of the acquisition of the assets comprising the Pacific Terminals storage and terminaling system.
August 1, 2003	Items 5 & 7	Filed in connection with the filing of the consolidated balance sheets of Pacific Energy GP, Inc., as of December 31, 2002 and as of June 30, 2003 (unaudited).
August 19, 2003	Items 5 & 7	Filed in connection with the filing of the underwriting agreement as an exhibit to the Form S-3 filing on August 8, 2003.
August 27, 2003	Items 5 & 7	Filed in connection with the sale of an additional 500,000 common units and the redemption of 500,000 common units held by Pacific Energy GP, Inc.
August 27, 2003	Items 5 & 7	Filed in connection with the sale of an additional 112,100 common units and the redemption of 112,100 common units held by Pacific Energy GP, Inc.

Date of Event Reported	Item(s) Reported	Description
August 28, 2003	Items 5 & 7	Filed in connection with the amendment and restatement of the Form 8-K as filed on August 29, 2003 to correct certain typographical errors.

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

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SIGNATURES

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

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

November 5, 2003 By: /s/ IRVIN TOOLE, JR.

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

November 5, 2003 By: /s/ GERALD A. TYWONIUK

Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

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EXHIBIT INDEX

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Filed herewith.

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