

PACIFIC ENERGY PARTNERS LP  
Form 10-Q  
August 08, 2006

**UNITED STATES  
SECURITIES AND EXCHANGE COMMISSION**

WASHINGTON, D.C. 20549

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**FORM 10-Q**

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

For the quarterly period ended June 30, 2006

OR

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

For the transition period from \_\_\_\_\_ to \_\_\_\_\_

Commission File Number 1-31345

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**PACIFIC ENERGY PARTNERS, L.P.**

(Exact name of registrant as specified in its charter)

**DELAWARE**  
(State or other jurisdiction  
of incorporation or organization)

**68-0490580**  
(I.R.S. Employer  
Identification No.)

**5900 Cherry Avenue**

**Long Beach, CA 90805-4408**

(Address of principal executive offices)

**(562) 728-2800**

(Registrant's telephone number, including area code)

**None**

(Former name, former address and former fiscal year, if changed since last report)

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

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Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

Large accelerated filer

Accelerated filer

Non-accelerated filer

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes  No

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

<b>Class</b>	<b>Outstanding at July 31, 2006</b>
Common Units	31,457,782
Subordinated Units	7,848,750

PACIFIC ENERGY PARTNERS, L.P.

FORM 10-Q

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**PART I. FINANCIAL INFORMATION****ITEM 1. Financial Statements****PACIFIC ENERGY PARTNERS, L.P.  
CONDENSED CONSOLIDATED BALANCE SHEETS  
(Unaudited)**

	<b>June 30, 2006</b>	<b>December 31, 2005</b>
	<b>(in thousands)</b>	
<b>ASSETS</b>		
Current assets:		
Cash and cash equivalents	\$ 22,823	\$ 18,064
Crude oil sales receivable	149,674	95,952
Transportation and storage accounts receivable	27,479	30,100
Canadian goods and services tax receivable	5,338	8,738
Insurance proceeds receivable	5,800	9,052
Due from related parties	141	
Crude oil and refined products inventory	36,193	20,192
Prepaid expenses	3,717	7,489
Other	3,524	2,528
Total current assets	254,689	192,115
Property and equipment, net	1,237,794	1,185,534
Intangible assets, net	69,354	69,180
Investment in Frontier	8,322	8,156
Other assets, net	17,791	21,467
	<b>\$ 1,587,950</b>	<b>\$ 1,476,452</b>
<b>LIABILITIES AND PARTNERS CAPITAL</b>		
Current liabilities:		
Accounts payable and accrued liabilities	\$ 37,838	\$ 42,409
Accrued crude oil purchases	145,041	96,651
Line 63 oil release reserve	4,480	5,898
Accrued interest	5,320	4,929
Other	12,459	6,300
Total current liabilities	205,138	156,187
Senior notes and credit facilities, net	635,368	565,632
Deferred income taxes	32,833	35,771
Environmental liabilities	16,572	16,617
Other liabilities	6,006	4,006
Total liabilities	895,917	778,213
Commitments and contingencies (note 6)		
Partners capital:		
Common unitholders (31,457,782 and 31,448,931 units outstanding at June 30, 2006 and December 31, 2005, respectively)	635,706	644,589
Subordinated unitholders (7,848,750 units outstanding at June 30, 2006 and December 31, 2005)	22,474	24,758
General Partner interest	12,295	12,535
Undistributed employee long-term incentive compensation	231	
Accumulated other comprehensive income	21,327	16,357
Net partners capital	692,033	698,239
	<b>\$ 1,587,950</b>	<b>\$ 1,476,452</b>

See accompanying notes to condensed consolidated financial statements.

**PACIFIC ENERGY PARTNERS, L.P.**  
**CONDENSED CONSOLIDATED STATEMENTS OF INCOME**  
(Unaudited)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2006		2005		2006		2005	
	(in thousands, except per unit amounts)							
<b>Revenues:</b>								
Pipeline transportation revenue	\$	34,800	\$	27,747	\$	68,657	\$	55,784
Storage and terminaling revenue		21,867		10,870		41,953		21,192
Pipeline buy/sell transportation revenue		11,427		8,116		21,126		17,222
Crude oil sales, net of purchases of \$353,590 and \$122,442 for the three months ended June 30, 2006 and 2005 and \$609,909 and \$236,833 for the six months ended June 30, 2006 and 2005		10,720		6,042		17,529		7,824
		78,814		52,775		149,265		102,022
<b>Cost and Expenses:</b>								
Operating (which excludes \$586 of compensation expense for the six months ended June 30, 2005 reported in accelerated long-term incentive plan compensation expense)		31,655		25,292		65,074		47,046
General and administrative (which excludes \$2,529 of compensation expense for the six months ended June 30, 2005 reported in accelerated long-term incentive plan compensation expense)		5,714		3,700		12,587		8,872
Depreciation and amortization		10,292		6,606		20,294		13,135
Merger costs (note 2)		3,417				3,417		
Accelerated long-term incentive plan compensation expense (note 7)								3,115
Line 63 oil release costs (note 6)								2,000
Reimbursed general partner transaction costs (note 5)								1,807
		51,078		35,598		101,372		75,975
Share of net income of Frontier		475		490		873		847
Operating income		28,211		17,667		48,766		26,894
Interest expense		(10,088)		(5,844)		(19,176)		(11,442)
Interest and other income		292		540		735		893
Income before income taxes		18,415		12,363		30,325		16,345
Income tax (expense) benefit:								
Current		(1,409)		245		(1,803)		(487)
Deferred (note 3)		4,437		(388)		4,535		(217)
		3,028		(143)		2,732		(704)
Net income	\$	21,443	\$	12,220	\$	33,057	\$	15,641
Net income (loss) for the general partner interest	\$	392	\$	244	\$	373	\$	(1,458)
Net income for the limited partner interests	\$	21,051	\$	11,976	\$	32,684	\$	17,099
Basic and diluted net income per limited partner unit	\$	0.54	\$	0.40	\$	0.83	\$	0.58
<b>Weighted average limited partner units outstanding:</b>								
Basic		39,307		29,723		39,304		29,689
Diluted		39,314		29,742		39,322		29,708

See accompanying notes to condensed consolidated financial statements.

**PACIFIC ENERGY PARTNERS, L.P.**  
**CONDENSED CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL**  
(Unaudited)

	Limited Partner Units Common Subordinated		Limited Partner Amounts Common Subordinated		General Partner Interest	Undistributed Employee Long-Term Incentive Compensation	Accumulated Other Comprehensive Income	Total
	(in thousands)							
Balance, December 31, 2005	31,449	7,849	\$ 644,589	\$ 24,758	\$ 12,535	\$	\$ 16,357	\$ 698,239
Net income			26,158	6,526	373			33,057
Distribution to partners			(35,306 )	(8,810 )	(1,498 )			(45,614 )
Employee compensation under LB Pacific, LP option plan					880			880
Employee compensation under long-term incentive plan						546		546
Issuance of common units pursuant to long-term incentive plan	9		265		5	(315 )		(45 )
Foreign currency translation adjustment							5,144	5,144
Change in fair value of crude oil and foreign currency hedging contracts							(174 )	(174 )
Balance, June 30, 2006	31,458	7,849	\$ 635,706	\$ 22,474	\$ 12,295	\$ 231	\$ 21,327	\$ 692,033

See accompanying notes to condensed consolidated financial statements.

**PACIFIC ENERGY PARTNERS, L.P.**  
**CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**  
(Unaudited)

	Three Months Ended June 30,				Six Months Ended June 30,						
	2006		2005		2006		2005				
	(in thousands)										
Net income	\$	21,443		\$	12,220		\$	33,057		\$	15,641
Change in fair value of crude oil and hedging derivatives					327			260			(806)
Change in fair value of foreign currency hedging derivatives		(488)	)					(434)	)		
Change in foreign currency translation adjustment		5,413			(1,765)	)		5,144			(2,301)
Comprehensive income	\$	26,368		\$	10,782		\$	38,027		\$	12,534

See accompanying notes to condensed consolidated financial statements.

**PACIFIC ENERGY PARTNERS, L.P.**  
**CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS**  
**(Unaudited)**

	Six Months Ended June 30,	
	2006	2005
	(in thousands)	
<b>CASH FLOWS FROM OPERATING ACTIVITIES</b>		
Net income	\$ 33,057	\$ 15,641
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	20,294	13,135
Amortization of debt issue costs	1,222	937
Non-cash of employee compensation under long-term incentive plan	546	2,886
Non-cash employee compensation under the LB Pacific, LP Option Plan	880	
Deferred tax expense (benefit)	(4,535)	217
Share of net income of Frontier	(873)	(847)
Other adjustments	(1,649)	98
Distributions from Frontier, net	622	650
Net changes in operating assets and liabilities:		
Crude oil sales receivable	(52,795)	(8,819)
Transportation and storage accounts receivable	2,723	1,699
Insurance proceeds receivable	5,476	(6,705)
Crude oil and refined products inventory	(15,693)	963
Other current assets and liabilities	11,752	1,079
Accounts payable and other accrued liabilities	(3,034)	9,638
Accrued crude oil purchases	47,204	11,113
Line 63 oil release reserve	(3,643)	4,981
Other non-current assets and liabilities	534	(522)
<b>NET CASH PROVIDED BY OPERATING ACTIVITIES</b>	<b>42,088</b>	<b>46,144</b>
<b>CASH FLOWS FROM INVESTING ACTIVITIES</b>		
Acquisitions	(2,365)	
Additions to property and equipment	(42,524)	(9,877)
Additions to pipeline linefill and minimum tank inventory	(16,419)	
Other	168	(98)
<b>NET CASH USED IN INVESTING ACTIVITIES</b>	<b>(61,140)</b>	<b>(9,975)</b>
<b>CASH FLOWS FROM FINANCING ACTIVITIES</b>		
Capital contributions from the general partner		2,438
Proceeds from credit facilities	130,409	66,283
Repayment of credit facilities	(60,950)	(64,326)
Deferred financing costs		(600)
Distributions to partners	(45,614)	(30,658)
Related parties	(141)	(686)
<b>NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES</b>	<b>23,704</b>	<b>(27,549)</b>
Effect of exchange rates on cash	107	74
<b>NET INCREASE IN CASH AND CASH EQUIVALENTS</b>	<b>4,759</b>	<b>8,694</b>
<b>CASH AND CASH EQUIVALENTS, beginning of reporting period</b>	<b>18,064</b>	<b>23,383</b>
<b>CASH AND CASH EQUIVALENTS, end of reporting period</b>	<b>\$ 22,823</b>	<b>\$ 32,077</b>

See accompanying notes to condensed consolidated financial statements.





**PACIFIC ENERGY PARTNERS, L.P.**  
**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS**  
**June 30, 2006**  
**(Unaudited)**

**1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES**

**Basis of Presentation**

Pacific Energy Partners, L.P. and its subsidiaries (collectively, the Partnership) are engaged principally in the business of gathering, transporting, storing and distributing crude oil, refined products and other related products. The Partnership generates revenue primarily by transporting such commodities on its pipelines, by leasing storage capacity in its storage tanks, and by providing other terminaling services. The Partnership also buys and sells crude oil, activities that are generally complementary to its other crude oil operations. The Partnership conducts its business through two business units, the West Coast Business Unit, which includes activities in California and the Philadelphia, Pennsylvania area, and the Rocky Mountain Business Unit, which includes activities in five Rocky Mountain states and Alberta, Canada.

The Partnership is managed by its general partner, Pacific Energy GP, LP, a Delaware limited partnership, which is managed by its general partner, Pacific Energy Management LLC (PEM), a Delaware limited liability company. Thus, the officers and board of directors of PEM manage the business affairs of Pacific Energy GP, LP and the Partnership. References to the General Partner refer to Pacific Energy GP, LP and/or PEM, as the context indicates: and Board of Directors refers to the board of directors of PEM.

The unaudited condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America for interim financial reporting and with Securities and Exchange Commission (SEC) regulations. Accordingly, these statements have been condensed and do not include all of the information and footnotes required for complete financial statements. These statements involve the use of estimates and judgments where appropriate. In the opinion of management, all adjustments, consisting of normal recurring accruals considered necessary for a fair presentation, have been included. The results of operations for the six months ended June 30, 2006 are not necessarily indicative of the results of operations for the full year. All significant intercompany balances and transactions have been eliminated during the consolidation process.

The condensed consolidated financial statements include the ownership and results of operations of the assets acquired from Valero, L.P., since the acquisition of these assets on September 30, 2005. The assets acquired from Valero, L.P. have been integrated into our West Coast and Rocky Mountain Business Units as the Pacific Atlantic Terminals and the Rocky Mountain Products Pipeline.

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, 2005. Certain prior year balances in the accompanying condensed consolidated financial statements have been reclassified to conform to the current year presentation.

**New Accounting Pronouncements**

In December 2004, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 123 (revised December 2004), *Share-Based Payment (SFAS 123R)*. This Statement is a revision of SFAS No. 123. SFAS 123R establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services. SFAS 123R is

effective for the Partnership as of the beginning of the first interim period or annual reporting period that begins after June 15, 2005. The adoption of SFAS 123R on January 1, 2006 did not have a material impact on the Partnership's consolidated financial statements. See Notes 4 and 7 to the condensed consolidated financial statements for more details on share-based compensation.

In September 2005, the Emerging Issues Task Force ( EITF ) issued Issue No. 04-13 ( EITF 04-13 ), *Accounting for Purchases and Sales of Inventory with the Same Counterparty*. The issues addressed by the EITF are (i) the circumstances under which two or more exchange transactions involving inventory with the same counterparty should be viewed as a single exchange transaction for the purposes of evaluating the effect of APB No. 29; and (ii) whether there are circumstances under which nonmonetary exchanges of inventory within the same line of business should be recognized at fair value. EITF 04-13 is effective for new arrangements entered into in the reporting periods beginning after March 15, 2006, and to all inventory transactions that are completed after December 15, 2006, for arrangements entered into prior to March 15, 2006. The adoption of EITF 04-13 did not have a material impact on the Partnership's consolidated financial statements.

In June 2006, the FASB issued FASB Interpretation No. 48 ( FIN 48 ), *Accounting for Uncertainty in Income Taxes*. This Interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. This Interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. FIN 48 will apply to the Partnership's Canadian subsidiaries, which are taxable entities in Canada. The Partnership is in the process of determining the impact of FIN 48 on its financial statements, but does not expect it to have a material impact. FIN 48 is effective for the Partnership as of the beginning of the first fiscal year beginning on January 1, 2007.

In June 2006, the EITF issued Issue No. 06-3 ( EITF 06-3 ), *How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation)*. The issues addressed by the EITF are (i) whether the scope of this Issue should include (a) all nondiscretionary amounts assessed by governmental authorities, (b) all nondiscretionary amounts assessed by governmental authorities in connection with a transaction with a customer, or (c) only sales, use, and value added taxes, and (ii) how taxes assessed by a governmental authority within the scope of this issue should be presented in the income statement (that is, gross versus net presentation). EITF 06-3 is effective for interim and annual financial periods beginning after December 15, 2006. The Partnership is in the process of determining the impact of EITF 06-3 on its financial statements, but does not expect it to have a material impact.

## **2. PROPOSED MERGER WITH PLAINS ALL AMERICAN PIPELINE, L.P.**

On June 12, 2006, the Partnership announced that it had entered into an Agreement and Plan of Merger with Plains All American Pipeline, L.P. ( PAA ), Plains AAP, L.P., a Delaware limited partnership, Plains All American GP LLC ( PAA GP LLC ), PEM, and Pacific Energy GP, LP, pursuant to which the Partnership will be merged with and into PAA. In the merger, each common unitholder of the Partnership, except LB Pacific, LP ( LB Pacific ), the owner of the Partnership's General Partner, will receive 0.77 common units of PAA for each common unit of the Partnership that the unitholder owns. In addition, pursuant to a purchase agreement between LB Pacific and PAA, PAA will acquire from LB Pacific the general partner interest and incentive distribution rights of the Partnership as well as 2,616,250 common units and 7,848,750 subordinated units for total consideration of \$700 million in cash. The merger agreement was unanimously approved by the Board of Directors of PEM, as well as by the PAA GP LLC board of directors.

If the proposed transaction is ultimately consummated, the general partner and limited partner interests in the Partnership will be extinguished and the Partnership will cease to exist as a separate legal

entity. The Partnership's operating subsidiaries will be directly or indirectly owned by PAA. PAA's management team and board of directors will continue in their current roles and manage the combined company. The merger is expected to close in the fourth quarter of 2006.

Each of the Partnership and PAA made customary representations, warranties and covenants in the merger agreement, including covenants restricting the Partnership's ability to initiate or continue any discussions with any other person with respect to a business combination while the merger is pending or to engage in any of those discussions unless the failure to do so would be reasonably likely to constitute a violation of fiduciary duties. The merger agreement may be terminated by the Partnership and/or PAA in specified circumstances, and provides that upon termination of the merger agreement in circumstances involving a competing proposal to acquire the Partnership or PAA, the parties are required to pay one another termination fees of up to \$40 million. The merger is subject to the satisfaction or waiver of certain conditions, including, among others:

- the adoption and approval of the merger agreement and the merger by the affirmative vote of the holders of at least a majority of the Partnership's outstanding common units (excluding common units held by LB Pacific) and at least a majority of the Partnership's outstanding subordinated units, each voting as a separate class;
- the adoption and approval of the merger agreement and the merger by the affirmative vote of the holders of at least a majority of PAA's outstanding common units, and the approval of the issuance of PAA common units pursuant to the merger agreement by the affirmative vote of the holders of at least a majority of PAA's outstanding common units;
- receipt of required regulatory approvals, including pursuant to the Hart-Scott-Rodino Antitrust Improvements Act of 1976 and approvals of Canadian governmental authorities, the Federal Communications Commission, the Public Utilities Commission of the state of California and the Public Service Commission of the state of Wyoming (see Note 9 Subsequent Events );
- the continued effectiveness of PAA's registration statement on Form S-4 to register the PAA common units to be issued in the merger, and the approval for listing on the New York Stock Exchange of such PAA common units;
- the absence of any decree, order, injunction or law that prohibits the merger or makes the merger unlawful; and
- the consummation of the transactions contemplated by the purchase agreement between PAA and LB Pacific.

Each of PAA and LB Pacific made customary representations, warranties and covenants in the purchase agreement. The purchase agreement may be terminated by LB Pacific or PAA upon or after termination of the merger agreement, and may be terminated at any time by the mutual written agreement of LB Pacific and PAA. In addition, the purchase agreement is subject to customary closing conditions, including satisfaction of all conditions specified in the merger agreement.

During the three and six months ended June 30, 2006, the Partnership incurred approximately \$3.4 million in costs directly relating to the merger for investment banking fees, legal fees, and other transaction costs. Approximately \$0.7 million of investment banking fees were payable to affiliates of Lehman Brothers Inc., an indirect partial owner of the General Partner (see Note 5 Related Party Transactions ). These costs are included in the condensed consolidated statements of income under the caption Merger costs .

### 3. INCOME TAXES

The Partnership and its U.S. and Canadian subsidiaries are not taxable entities in the U.S. and are not subject to U.S. federal or state income taxes, as the tax effect of operations is passed through to its

unitholders. However, the Partnership's Canadian subsidiaries are taxable entities in Canada and are subject to Canadian federal and provincial income taxes. In addition, inter-company interest payments and repatriation of funds through dividend payments are subject to withholding tax.

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

During the quarter ended June 30, 2006, the Canadian and Alberta governments enacted legislation which will reduce federal and provincial income taxes. The Partnership adjusted the future income tax rates used in the estimates of deferred tax assets and liabilities and recognized a \$4.6 million deferred tax benefit during the three and six months ended June 30, 2006.

#### 4. NET INCOME PER LIMITED PARTNER UNIT

Net income is allocated to the Partnership's General Partner and limited partners based on their respective interest in the Partnership. The Partnership's General Partner is also directly charged with specific costs that it has individually assumed and for which the limited partners are not responsible.

Basic net income per limited partner unit is determined by dividing net income, after adding back costs and deducting certain amounts allocated to the General Partner (including incentive distribution payments in excess of its 2% ownership 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, if any, and restricted units by application of the treasury stock method.

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Set forth below is the computation of net income allocated to limited partners and net income per basic and diluted limited partner unit. The table also shows the reconciliation of basic average limited partner units to diluted weighted average limited partner units.

	Three Months Ended June 30,				Six Months Ended June 30,			
	2006		2005		2006		2005	
	(in thousands)							
<b>Numerator:</b>								
Net income allocated to limited partners:								
Net income	\$	21,443	\$	12,220	\$	33,057	\$	15,641
Costs allocated to the general partner(1):								
LBP Option Plan cost		369				880		
Senior Notes consent solicitation and other costs								893
Severance and other costs								914
Total costs allocated to the general partner		369				880		1,807
Income before costs allocated to the general partner		21,812		12,220		33,937		17,448
Less: general partner incentive distributions		(331)				(586)		
		21,481		12,220		33,351		17,448
Less: General partner 2% ownership		(430)		(244)		(667)		(349)
Net income for the limited partners	\$	21,051	\$	11,976	\$	32,684	\$	17,099
<b>Denominator:</b>								
Basic weighted average limited partner units		39,307		29,723		39,304		29,689
Effect of restricted units		7				18		
Effect of options				19				19
Diluted weighted average limited partner units		39,314		29,742		39,322		29,708
Basic and diluted net income per limited partner unit	\$	0.54	\$	0.40	\$	0.83	\$	0.58

(1) See Note 5 Related Party Transactions for a description of transaction costs reimbursed by the General Partner.

## 5. RELATED PARTY TRANSACTIONS

### Cost Reimbursements

**Managing General Partner:** The Partnership's General Partner employs all U.S.-based employees. All employee expenses incurred by the General Partner on behalf of the Partnership are charged back to the Partnership.

**LB Pacific, LP Option Plan:** LB Pacific, LP (LBP), the owner of the Partnership's General Partner, has adopted an option plan for certain officers, directors, employees, advisors, and consultants of PEM, LBP, and their affiliates. Under the plan, participants may be granted options to acquire partnership interests in LBP. The Partnership is not obligated to pay any amounts to LBP for the benefits granted or paid to any participants under the plan, although generally accepted accounting principles require that the Partnership record an expense in its financial statements for benefits granted to employees of PEM or the Partnership who provide services to the Partnership, with a corresponding increase in the General Partner's capital account.

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The option plan is administered by the board of directors of LB Pacific GP, LLC, the general partner of LBP. The terms, conditions, performance goals, restrictions, limitations, forfeiture, vesting or exercise schedule, and other provisions of grants under the plan, as well as eligibility to participate are determined by the board of directors of LB Pacific GP, LLC. The board of directors of LB Pacific GP, LLC may determine to grant options under the plan to participants containing such terms as the board of LB Pacific GP, LLC shall determine. Options will have an exercise price that may not be less than the fair market value of the units on the date of grant.

The board of directors of LB Pacific GP, LLC may terminate or amend the unit option plan at any time with respect to units for which a grant has not yet been made. However, no change may be made that would materially impair the rights of a participant with respect to an outstanding grant without the consent of the participant.

Information concerning the plan and grants is shared by LB Pacific, LP with the General Partner's Compensation Committee and Board of Directors, and considered in determining the long term incentive compensation paid by the Partnership to participants in the plan.

In January 2006, LBP granted options representing a maximum 24% interest in LBP (assuming all options vest and are exercised), which options vest over a period of 10 years from the date of grant (except in limited circumstances such as a change in control), to certain officers and key employees of PEM and the Partnership. The grants, qualified as equity-classified awards, had a grant date fair value of \$8.6 million. The fair value of the options was determined using valuation techniques that included the discounted present value of estimated future cash flows for LBP and fundamental analysis. It was measured using the Black-Scholes option pricing model with the following assumptions:

Expected volatility	21.86 %
Expected dividend yield	0 %
Expected term (in years)	10
Risk-free rate	4.37 %

For the three and six months ended June 30, 2006, the Partnership recognized \$0.4 million and \$0.9 million in compensation expense relating to the LBP options and recorded a capital contribution from the General Partner for the same amounts. At June 30, 2006, all granted LBP options remained outstanding. At June 30, 2006, there was \$7.7 million of total unrecognized compensation cost related to nonvested options granted under the plan which cost was expected to be recognized over the remaining period of 9.5 years. Upon the close of the proposed merger with PAA, the options will become immediately exercisable. Total unrecognized compensation expense on the closing date will be immediately recognized in the income statement.

**LB Pacific, LP and Anschutz:** Prior to March 3, 2005, the General Partner was owned by The Anschutz Corporation (Anschutz). On March 3, 2005, Anschutz sold its interest in the Partnership, including its interest in the General Partner, to LBP. In connection with the sale of Anschutz's interest in the Partnership to LBP, LBP and Anschutz reimbursed the Partnership for certain costs incurred in connection with the acquisition. The Partnership was reimbursed \$1.2 million for costs incurred in connection with the consent solicitation, \$0.3 million of legal and other costs, and \$0.9 million relating to severance costs, for a total of \$2.4 million. Of the \$2.4 million total incurred, \$1.8 million was expensed, as shown on the income statement as reimbursed general partner transaction costs, and \$0.6 million of the consent solicitation costs were capitalized as deferred financing costs.

**Special Agreement:** On March 3, 2005, Douglas L. Polson, previously the Chairman of the Board of Directors entered into a Special Agreement and a Consulting Agreement with PEM. In accordance with the Special Agreement, Mr. Polson resigned as Chairman of the Board of Directors effective March 3,

2005. Mr. Polson was paid approximately \$0.9 million, representing accrued salary through March 3, 2005, accrued but unused vacation and payment in satisfaction of other obligations under his employment agreement. The latter portion of this payment was recorded as an expense in Reimbursed general partner transaction costs in the accompanying condensed consolidated income statements. LBP reimbursed this amount, which was recorded as a partner's capital contribution. Pursuant to the Consulting Agreement, Mr. Polson agreed to perform advisory services to PEM from time to time as mutually agreed between Mr. Polson and the Chief Executive Officer of PEM. In consideration for Mr. Polson's services under the Consulting Agreement, which had a one-year term, Mr. Polson received a monthly consulting fee of \$12,500 and reimbursement of all reasonable business expenses incurred or paid by Mr. Polson in the course of performing his duties thereunder.

#### **Lehman Brothers, Inc.**

Lehman Brothers, Inc. is deemed to be an affiliate of the Partnership's General Partner through a 59% ownership interest in LBP, which is controlled by Lehman Brothers Holdings Inc., the parent entity of Lehman Brothers, Inc. Lehman Brothers, Inc. acted as financial advisor to LBP and the Partnership in connection with the proposed merger and the transactions related to the merger (see Note 2 Proposed Merger With Plains All American, L.P.). Lehman Brothers, Inc. delivered an opinion to the Board of Directors to the effect that, as of the date of its opinion and based on and subject to various assumptions made, the aggregate consideration to be offered to all of the holders of the partnership interests in the Partnership in the proposed transaction is fair to such holders. The agreement with Lehman Brothers, Inc. was reviewed and approved by the Conflicts Committee of the Board of Directors and the fees charged were customary for the type of services provided. For the three and six months ended June 30, 2006, the Partnership incurred \$0.7 million in fees with Lehman Brothers, Inc. The Partnership has agreed to pay Lehman Brothers, Inc. an additional \$7.7 million success fee contingent on the successful consummation of the merger.

#### **Other Related Party Transactions**

RMPS receives an operating fee and management fee from Frontier Pipeline Company ( Frontier ) in connection with time spent by RMPS management and for other services related to Frontier's activities. RMPS received \$0.2 million for each of the three months ended June 30, 2006 and 2005 and \$0.4 million for each of the six months ended June 30, 2006 and 2005, respectively. The Partnership owns a 22.22% partnership interest in Frontier.

### **6. CONTINGENCIES**

#### **Line 63 Oil Release**

On March 23, 2005, a release of approximately 3,400 barrels of crude oil occurred on Line 63 when it was severed as a result of a landslide caused by heavy rainfall in the Pyramid Lake area of Los Angeles County. Over the period March 2005 through anticipated completion in June 2007, the Partnership expects to incur an estimated total of \$25.5 million for oil containment and clean-up of the impacted areas, future monitoring costs, potential third-party claims and penalties, and other costs, excluding pipeline repair costs. As of June 30, 2006, the Partnership had incurred approximately \$21.1 million of the total expected remediation costs related to the oil release for work performed through that date. The Partnership estimates that the \$4.4 million of remaining remediation cost will be incurred before June 2007.

The Partnership has a pollution liability insurance policy with a \$2.0 million per-occurrence deductible that covers containment and clean-up costs, third-party claims and certain penalties. The insurance carrier has, subject to the terms of the insurance policy, acknowledged coverage of the incident and is processing and paying invoices related to the clean-up. The Partnership believes that, subject to the \$2.0 million



deductible, it will be entitled to recover substantially all of its clean-up costs and any third-party claims associated with the release. As of June 30, 2006, the Partnership has recovered \$17.7 million from insurance and recorded receivables of \$5.8 million for future insurance recoveries it deems probable.

On or about March 17, 2006, Pacific Pipeline System LLC ( PPS ), a subsidiary of the Partnership, was served with a four count misdemeanor action by the state of California, which alleges that PPS violated various state statutes by depositing oil or substances harmful to wildlife into the environment and by the willful and intentional discharge of pollution into state waters. The Partnership estimates that the maximum fine and penalties that could be assessed for these actions is approximately \$0.9 million in the aggregate. The Partnership believes, however, that certain of the alleged violations are without merit and intends to defend against them, and that mitigating factors should otherwise reduce the amounts of any potential fines or penalties that might be assessed. At this time, the Partnership cannot reasonably determine the outcome of these allegations. The estimated range of possible fines or penalties including amounts not covered by insurance is between \$0 and \$0.9 million.

The foregoing estimates are based on facts known at the time of estimation and the Partnership's assessment of the ultimate outcome. Among the many uncertainties that impact the estimates are the necessary regulatory approvals for, and potential modification of, remediation plans, the ongoing assessment of the impact of soil and water contamination, changes in costs associated with environmental remediation services and equipment, and the possibility of third-party legal claims giving rise to additional expenses. Therefore, no assurance can be made that costs incurred in excess of this provision, if any, would not have a material adverse effect on the Partnership's financial condition, results of operations, or cash flows, though the Partnership believes that most, if not all, of any such excess cost, to the extent attributable to clean-up and third-party claims, would be recoverable through insurance. In March 2006, A.M. Best Company, an insurance company rating agency, announced it had downgraded the financial strength rating assigned to the Partnership's insurance carrier, Quanta Specialty Lines Company, including its parent and affiliates. The downgrade was from an A to a B++, under review with negative implications. During the second quarter of 2006, Quanta announced that their Board of Directors decided to cease underwriting or seeking new business and to place most of its remaining specialty insurance and reinsurance lines into orderly run-off. On June 7, 2006 A. M. Best further downgraded Quanta from B++ to B. Subsequent to this downgrading, Quanta was removed from A. M. Best's interactive rating process, at Quanta's request. Based on management's further analysis of Quanta's financial condition, the Partnership believes that Quanta will continue to meet its obligations relating to the Line 63 oil release, although there can be no assurance that this will be the case. As new information becomes available in future periods, the Partnership may change its provision and recovery estimates.

#### **Product Contamination**

In June 2006, approximately 44,000 barrels of a customer's product at our Martinez terminal was contaminated. The Partnership has insurance coverage for the damage or loss of its customers' products while in its care, custody and control at certain of its terminals subject to a \$0.1 million per-occurrence deductible. The Partnership recognized a loss of \$0.2 million to cover the insurance deductible and other associated costs. At this time, the Partnership believes all other estimated net costs related to the contamination of the property will be covered under the insurance policy, and has accrued for the insurance deductible and other costs of \$0.2 million, which is included in Other current liabilities in the accompanying condensed consolidated balance sheet. The estimated range of total net costs is from \$0.2 million to \$0.8 million.

#### **Litigation**

On June 15, 2006, a lawsuit was filed in the Superior court of California, County of Los Angeles, entitled Kosseff v. Pacific Energy, et al, case no. BC 3544016. The plaintiff alleges that he is a unitholder of

Partnership and seeks to represent a class comprising all of the Partnership's unitholders. The complaint names as defendants the Partnership and certain of the officers and directors of Pacific's general partner, and asserts claims of self-dealing and breach of fiduciary duty in connection with the pending merger with PAA and related transactions. Among other allegations, the plaintiff alleges that (1) the proposed transaction was the product of a flawed process that would result in the sale of the Partnership at an unfairly low price, (2) subsequent quarterly financial results for the Partnership would have had a material positive impact on the Partnership's common unit price had the proposed transaction not been announced, and thus the premium being offered to the Partnership's unitholders was manufactured by the defendants based on the timing of the announcement of the proposed transaction, (3) because of various conflicts of interest, the defendants have acted to better their own interests at the expense of the Partnership's public unitholders, (4) the defendants favored the proposed transaction in order to secure accelerated vesting of equity compensation under change in control provisions in contracts they have with the Partnership, and (5) the defendants were assured that Lehman Brothers Inc. would rubber-stamp the transaction as fair and, for that reason Lehman [Brothers Inc.] was hand-picked by the defendants to issue the so-called fairness opinion. The plaintiff seeks injunctive relief against completing the merger or, if the merger is completed, rescission of the merger, other equitable relief, and recovery of the plaintiff's costs and attorneys' fees. The Partnership believes that the lawsuit is without merit and intends to defend against it vigorously. There can be no assurance that additional claims may not be made or filed, the substance of which may be similar to the allegations described above or that otherwise might arise from, or in connection with, the merger agreement and the transaction it contemplates.

In August, 2005, Rangeland Pipeline Company (RPC), a wholly-owned subsidiary of the Partnership, learned that a Statement of Claim was filed by Desiree Meier and Robert Meier in the Alberta Court of Queen's Bench, Judicial District of Red Deer, naming RPC as defendant, and alleging personal injury and property damage caused by an alleged release of petroleum substances onto plaintiff's land by a prior owner and operator of the pipeline that is currently owned and operated by the Partnership. The claim seeks Cdn\$1 million (approximately U.S.\$0.9 million at June 30, 2006) in general damages, Cdn\$2 million (approximately U.S.\$1.8 million at June 30, 2006) in special damages, and, in addition, unspecified amounts for punitive, exemplary and aggravated damages, costs and interest. RPC believes the claim is without merit, and intends to vigorously defend against it. RPC also believes that certain of the claims, if successfully proven by the plaintiffs, would be liabilities retained by the pipeline's prior owner under the terms of the agreement whereby the Partnership acquired the pipeline in question.

In connection with the acquisition of assets from Valero, L.P. in September 2005, the Partnership assumed responsibility for the defense of a lawsuit filed in 2003 against Support Terminals Services, Inc. (ST Services) by ExxonMobil Corporation (ExxonMobil) in New Jersey state court. The Partnership has also assumed any liability that might be imposed on ST Services as a result of the suit. In the suit, ExxonMobil seeks reimbursement of approximately \$400,000 for remediation costs it has incurred, from GATX Corporation, Kinder Morgan Liquid Terminals, the successor in interest to GATX Terminals Corporation, and ST Services. ExxonMobil also seeks a ruling imposing liability for any future remediation and related liabilities on the same defendants. These costs are associated with the Paulsboro, New Jersey terminal that was acquired by the Partnership on September 30, 2005. ExxonMobil claims that the costs and future remediation requirements are related to releases at the site subsequent to its sale of the terminal to GATX in 1990 and that, therefore, any remaining remediation requirements are the responsibility of GATX Corporation, Kinder Morgan and ST Services. The Partnership believes the claims against ST Services are without merit, and intend to vigorously defend against them.

In 2001, Big West Oil Company and Chevron Products Company (the Complainants) filed complaints against Frontier Pipeline Company (Frontier) with the Federal Energy Regulatory Commission (FERC) challenging rates contained in joint tariffs in which Frontier was a participating carrier and rates contained in local tariffs filed by Frontier. On February 18, 2004, the FERC found against

Frontier on certain of the Complainants' claims and ordered Frontier to pay reparations to Complainants in the aggregate amount of approximately \$4.2 million, plus interest, which Frontier paid in August 2004. On October 5, 2004, Frontier filed a petition for review of the FERC's reparations orders in the U.S. Court of Appeals for the D.C. Circuit, and on May 26, 2006 the Court of Appeals held that the FERC's reparation ruling was inconsistent with applicable law, and thus vacated the FERC's order and remanded the matter back to the FERC for further consideration consistent with the Court of Appeals' decision. On July 25, 2006, Frontier filed a motion asking the FERC to dismiss the reparations complaints of the Complainants on the grounds that their complaints fail to state claims that can be sustained consistent with the ruling of the Court of Appeals. Frontier's motion also asked the FERC to order the refund by the Complainants of the reparations previously paid by Frontier, plus interest. The Complainants have not yet responded to Frontier's motion and no action on the motion has been taken by the FERC. If Frontier prevails on its motion or in any remand proceeding conducted by the FERC, it would be entitled to repayment in the amount of \$5.4 million, plus interest thereon from August 23, 2004. The Partnership owns 22.22% of Frontier. Although the Partnership believes Frontier's motion to dismiss the complaints, as well as the defenses it would assert in a remand proceeding before the FERC, are meritorious, the Partnership cannot predict the outcome of any such actions, and has not recorded any amount for this contingency.

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

## 7. RESTRICTED UNITS

A restricted unit is a phantom unit under the Partnership's long term incentive compensation plan. A phantom unit entitles the grantee to receive a common unit upon the vesting of the phantom unit. The Partnership intends the issuance of the restricted units under the plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, plan participants will not pay any consideration for the common units they receive, and the Partnership will receive no remuneration for such units.

In January 2006 and May 2006, the General Partner awarded 89,110 restricted units to key employees and outside directors that vest over a three-year period, beginning on March 1, 2006 and March 1, 2007, respectively. The number of units to be delivered to key employees in any year, if any, will be based on accomplishment of performance targets (measured by distributable cash flow) for the previous calendar year, subject to the Compensation Committee's authority to subsequently adjust performance targets as it may deem appropriate, in its discretion. Restricted unit activity during the six months ended June 30, 2006 is as follows:

	Number of Units	Weighted Average Grant Date Fair Value
Outstanding at January 1, 2006		\$
Changes during the year:		
Granted	89,110	2,759
Vested	(10,439)	(314)
Forfeited	(5,430)	(164)
Outstanding at June 30, 2006	73,241	\$ 2,281

Compensation expense recognized for outstanding restricted units is based on grant date fair value of the common units to be awarded to the grantee upon vesting of the phantom unit, adjusted for the expected target performance level for each year. For the three and six months ended June 30, 2006, the

Partnership incurred \$0.2 million and \$0.5 million, respectively, in compensation expense for restricted units it deemed probable of achieving the performance criteria, including the amount for the first vesting of these awards which occurred on March 1, 2006.

The outstanding unit grants include change of control provisions that require immediate vesting of units in the event of a change in control of the Partnership or its General Partner. Upon the close of the proposed merger with PAA, all outstanding restricted units will immediately vest pursuant to the terms of the grants, and any remaining unamortized compensation expense will be immediately recognized.

On March 3, 2005, in connection with LBP's acquisition of the Partnership's General Partner, all restricted units then outstanding under the Partnership's Long-Term Incentive Plan immediately vested pursuant to the terms of the grants. The Partnership issued 99,583 common units and recognized a compensation expense of \$3.1 million, which is included in Accelerated long-term incentive plan compensation expense in the accompanying condensed consolidated statements of income. Of the total \$3.1 million, the compensation expense categorization was \$0.6 million for operating personnel and \$2.5 million for general and administrative personnel.

## 8. SEGMENT INFORMATION

The Partnership's business and operations are organized into two business segments: the West Coast Business Unit and the Rocky Mountain Business Unit. The West Coast Business Unit includes: (i) Pacific Pipeline System LLC, owner of Line 2000 and Line 63, (ii) Pacific Marketing and Transportation LLC (West Coast Business Unit operations), owner of the PMT gathering system and marketer of crude oil, (iii) Pacific Terminals LLC, owner of the Pacific Terminals storage and distribution system, and (iv) Pacific Atlantic Terminals LLC, owner of the San Francisco and Philadelphia area terminals, which were acquired on September 30, 2005. The Rocky Mountain Business Unit includes: (i) Rocky Mountain Pipeline System LLC, owner of the Partnership's interest in various pipelines that make up the Western Corridor and Salt Lake City Core systems, and the Rocky Mountain Products Pipeline, which was acquired on September 30, 2005, (ii) Ranch Pipeline LLC, the owner of a 22.22% partnership interest in Frontier Pipeline Company, (iii) PEG Canada, L.P. and its Canadian subsidiaries, which own and operate the Rangeland system, and (iv) Pacific Marketing and Transportation LLC (Rocky Mountain Business Unit operations), a marketer of crude oil.

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General and administrative costs, which consist of executive management, accounting and finance, human resources, information technology, investor relations, legal, and business development, are not allocated to the individual business units. Information regarding these two business units is summarized below:

	West Coast Business Unit		Rocky Mountain Business Unit		Intersegment and Intrasegment Eliminations		Total
	(in thousands)						
<b>Three months ended June 30, 2006</b>							
Revenues:							
Pipeline transportation revenue	\$	16,696	\$	20,422	\$	(2,318 )	\$ 34,800
Storage and terminaling revenue		21,867					21,867
Pipeline buy/sell transportation revenue(1)				11,427			11,427
Crude oil sales, net of purchases(2)		9,195		1,648		(123 )	10,720
Net revenue		47,758		33,497			78,814
Expenses:							
Operating		20,263		13,833		(2,441 )	31,655
Depreciation and amortization		5,507		4,785			10,292
Total expenses		25,770		18,618			41,947
Share of net income of Frontier				475			475
Operating income from segments(3)	\$	21,988	\$	15,354			\$ 37,342
Total business unit assets(4)	\$	20,546	\$	55,884			\$ 76,430
Capital expenditures(5)	\$	10,017	\$	5,869			\$ 15,886
<b>Three months ended June 30, 2005</b>							
Revenues:							
Pipeline transportation revenue	\$	15,194	\$	14,006	\$	(1,453 )	\$ 27,747
Storage and terminaling revenue		10,870					10,870
Pipeline buy/sell transportation revenue(1)				8,116			8,116
Crude oil sales, net of purchases(2)		5,866		206		(30 )	6,042
Net revenue		31,930		22,328			52,775
Expenses:							
Operating		15,996		10,779		(1,483 )	25,292
Depreciation and amortization		3,529		3,077			6,606
Total expenses		19,525		13,856			31,898
Share of net income of Frontier				490			490
Operating income from segments(3)	\$	12,405	\$	8,962			\$ 21,367
Total business unit assets(4)	\$	501,990	\$	342,420			\$ 844,410
Capital expenditures(5)	\$	934	\$	2,535			\$ 3,469

	West Coast Business Unit	Rocky Mountain Business Unit	Intersegment and Intrasegment Eliminations	Total
	(in thousands)			
<b>Six months ended June 30, 2006</b>				
Revenues:				
Pipeline transportation revenue	\$ 33,859	\$ 39,290	\$ (4,492 )	\$ 68,657
Storage and terminaling revenue	41,953			41,953
Pipeline buy/sell transportation revenue(1)		21,126		21,126
Crude oil sales, net of purchases(2)	16,506	1,288	(265 )	17,529
Net revenue	92,318	61,704		149,265
Expenses:				
Operating	41,695	28,136	(4,757 )	65,074
Depreciation and amortization	11,006	9,288		20,294
Total expenses	52,701	37,424		85,368
Share of net income of Frontier		873		873
Operating income from segments(3)	\$ 39,617	\$ 25,153		\$ 64,770
Total business unit assets(4)	\$ 904,689	\$ 627,275		\$ 1,531,964
Capital expenditures(5)	\$ 21,627	\$ 11,685		\$ 33,312
<b>Six months ended June 30, 2005</b>				
Revenues:				
Pipeline transportation revenue	\$ 32,638	\$ 26,461	\$ (3,315 )	\$ 55,784
Storage and terminaling revenue	21,342		(150 )	21,192
Pipeline buy/sell transportation revenue(1)		17,222		17,222
Crude oil sales, net of purchases(2)	7,678	206	(60 )	7,824
Net revenue	61,658	43,889		102,022
Expenses:				
Operating	30,503	20,068	(3,525 )	47,046
Line 63 oil release costs(6)	2,000			2,000
Depreciation and amortization	7,006	6,129		13,135
Total expenses	39,509	26,197		62,181
Share of net income of Frontier		847		847
Operating income from segments(3)	\$ 22,149	\$ 18,539		\$ 40,688
Total business unit assets(4)	\$ 501,990	\$ 342,420		\$ 844,410
Capital expenditures(5)	\$ 1,684	\$ 5,467		\$ 7,151

(1) Pipeline buy/sell transportation revenue reflects net revenues of approximately \$4.3 million on buy/sell transactions with different parties of \$112.8 million for the three months ended June 30, 2006 and net revenues of approximately \$6.8 million on buy/sell transactions with different parties of \$161.1 million for the six months ended June 30, 2006. The remaining amount reflects net revenues on buy/sell transactions with the same party.

(2) The above amounts are net of purchases of \$353.6 million and \$122.4 million for the three months ended June 30, 2006 and 2005 and \$609.9 million and \$236.8 million for the six months ended June 30, 2006 and 2005, respectively.

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

	Three Months Ended June 30,				Six Months Ended June 30,						
	2006		2005		2006		2005				
	(in thousands)										
<b>Income Statement Reconciliation</b>											
Operating income from above:											
West Coast Business Unit	\$	21,988		\$	12,405		\$	39,617		\$	22,149
Rocky Mountain Business Unit		15,354			8,962			25,153			18,539
Operating income from segments		37,342			21,367			64,770			40,688
Less: General and administrative expense		(5,714)	)		(3,700)	)		(12,587)	)		(8,872)
Less: Merger costs		(3,417)	)					(3,417)	)		
Less: Accelerated long-term incentive plan compensation expense										(3,115)	)
Less: Reimbursed general partner transaction costs										(1,807)	)
Operating income		28,211			17,667			48,766			26,894
Interest expense		(10,088)	)		(5,844)	)		(19,176)	)		(11,442)
Other income		292			540			735			893
Income tax benefit (expense)		3,028			(143)	)		2,732			(704)
Net income	\$	21,443		\$	12,220		\$	33,057		\$	15,641

(4) Business unit assets do not include assets related to the Partnership's parent level activities. As of June 30, 2006 and 2005, parent level related assets were \$56.0 and \$39.9 respectively.

(5) Segment capital expenditures do not include parent level capital expenditures. Parent level capital expenditures were \$2.5 million and \$2.0 million for the three months ended June 30, 2006 and 2005 and \$9.2 million and \$2.7 million for the six months ended June 30, 2006 and 2005, respectively.

(6) On March 23, 2005, a release of approximately 3,400 barrels of crude oil occurred on PPS's Line 63 as a result of a landslide caused by heavy rainfall in northern Los Angeles County. As a result of the release, the Partnership recorded \$2.0 million net oil release costs in the first quarter of 2005, consisting of what it now estimates to be \$25.5 million of accrued costs relating to the release, net of insurance recovery of \$17.7 million to June 30, 2006 and accrued insurance receipts of \$5.8 million.

## 9. SUBSEQUENT EVENTS

On July 17, 2006, the Partnership declared a cash distribution of \$0.5675 per limited partner unit, payable on August 14, 2006, to unitholders of record as of August 1, 2006.

On August 1, 2006, the Partnership and PAA announced that the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, for the proposed merger expired on July 31, 2006. In addition, PAA has received a "no issues" letter from the Canadian Competitive Bureau and notice that the accompanying waiting period under the Competition Act has expired. These expirations satisfy certain of the closing conditions contained in the merger agreement (see Note 2 Proposed Merger With Plains All American Pipeline, L.P.).

## 10. SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

Certain of the Partnership's 100% owned subsidiaries have issued full, unconditional, and joint and several guarantees of the 7 1/8% senior notes due 2014 and the 6 1/4% senior notes due 2015 (the Senior Notes). Given that certain, but not all subsidiaries of the Partnership are guarantors of its Senior Notes, the Partnership is required to present the following supplemental condensed consolidating financial





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information. For purposes of the following footnote, the Partnership is referred to as Parent, while the Guarantor Subsidiaries are Rocky Mountain Pipeline System LLC, Pacific Marketing and Transportation LLC, Pacific Atlantic Terminals LLC, Ranch Pipeline LLC, PEG Canada GP LLC, PEG Canada, L.P. and Pacific Energy Group LLC, and Non-Guarantor Subsidiaries are Pacific Pipeline System LLC, Pacific Terminals LLC, Rangeland Pipeline Company, Rangeland Marketing Company, Rangeland Northern Pipeline Company, Rangeland Pipeline Partnership and Aurora Pipeline Company, Ltd.

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

	<b>Balance Sheet</b>				
	<b>June 30, 2006</b>				
	<b>Parent</b>	<b>Guarantor</b>	<b>Non-Guarantor</b>	<b>Consolidating</b>	<b>Total</b>
	<b>(in thousands)</b>	<b>Subsidiaries</b>	<b>Subsidiaries</b>	<b>Adjustments</b>	
<b>Assets:</b>					
Current assets	\$ 101,891	\$ 209,268	\$ 89,380	\$ (145,850 )	\$ 254,689
Property and equipment		611,503	626,291		1,237,794
Equity investments	485,158	219,253		(696,089 )	8,322
Intercompany notes receivable	661,763	343,849		(1,005,612 )	
Intangible assets		30,365	38,989		69,354
Other assets	12,048	(244 )	5,987		17,791
Total assets	\$ 1,260,860	\$ 1,413,994	\$ 760,647	\$ (1,847,551 )	\$ 1,587,950
<b>Liabilities and partners' capital:</b>					
Current liabilities	\$ 4,295	\$ 255,930	\$ 90,763	\$ (145,850 )	\$ 205,138
Long-term debt	562,044		73,324		635,368
Deferred income taxes		1,267	31,566		32,833
Intercompany notes payable		661,763	343,849	(1,005,612 )	
Other liabilities	2,488	9,876	10,214		22,578
Total partners' capital	692,033	485,158	210,931	(696,089 )	692,033
Total liabilities and partners' capital	\$ 1,260,860	\$ 1,413,994	\$ 760,647	\$ (1,847,551 )	\$ 1,587,950

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Balance Sheet December 31, 2005						
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total	
(in thousands)						
<b>Assets:</b>						
Current assets	\$ 104,989	\$ 139,457	\$ 81,846	\$ (134,177 )	\$ 192,115	
Property and equipment		583,330	602,204		1,185,534	
Equity investments	429,802	197,239		(618,885 )	8,156	
Intercompany notes receivable	661,313	340,905		(1,002,218 )		
Intangible assets		31,220	37,960		69,180	
Other assets	13,426		8,041		21,467	
<b>Total assets</b>	<b>\$ 1,209,530</b>	<b>\$ 1,292,151</b>	<b>\$ 730,051</b>	<b>\$ (1,755,280 )</b>	<b>\$ 1,476,452</b>	
<b>Liabilities and partners' capital:</b>						
Current liabilities	\$ 5,389	\$ 191,516	\$ 93,459	\$ (134,177 )	\$ 156,187	
Long-term debt	505,902		59,730		565,632	
Deferred income taxes		582	35,189		35,771	
Intercompany notes payable		661,313	340,905	(1,002,218 )		
Other liabilities		8,938	11,685		20,623	
<b>Total partners' capital</b>	<b>698,239</b>	<b>429,802</b>	<b>189,083</b>	<b>(618,885 )</b>	<b>698,239</b>	
<b>Total liabilities and partners' capital</b>	<b>\$ 1,209,530</b>	<b>\$ 1,292,151</b>	<b>\$ 730,051</b>	<b>\$ (1,755,280 )</b>	<b>\$ 1,476,452</b>	

Statement of Income Three Months Ended June 30, 2006						
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total	
(in thousands)						
Net operating revenues	\$	\$ 41,311	\$ 39,945	\$ (2,442 )	\$ 78,814	
Operating expenses		(19,794 )	(14,303 )	2,442	(31,655 )	
General and administrative expense(1)	(1 )	(5,163 )	(550 )		(5,714 )	
Merger costs		(3,417 )			(3,417 )	
Depreciation and amortization expense		(5,141 )	(5,151 )		(10,292 )	
Share of net income of Frontier		475			475	
Operating income	(1 )	8,271	19,941		28,211	
Interest expense	(8,894 )	(60 )	(1,134 )		(10,088 )	
Intercompany interest income (expense)		7,352	(7,352 )			
Equity earnings	30,420	15,700		(46,120 )		
Other income	(82 )	254	120		292	
Income tax (expense) benefit		(1,097 )	4,125		3,028	
<b>Net income</b>	<b>\$ 21,443</b>	<b>\$ 30,420</b>	<b>\$ 15,700</b>	<b>\$ (46,120 )</b>	<b>\$ 21,443</b>	

(1) General and administrative expense is not currently allocated between Guarantor and Non-Guarantor Subsidiaries for financial reporting purposes.

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	Statement of Income												
	Three Months Ended June 30, 2005												
	Parent		Guarantor Subsidiaries		Non-Guarantor Subsidiaries		Consolidating adjustments		Total				
	(in thousands)												
Net operating revenues	\$		\$	20,077		\$	34,181		\$	(1,483)		\$	52,775
Operating expenses			(10,322)	)		(16,453)	)		1,483			(25,292)	)
General and administrative expense(1)			(3,208)	)		(492)	)					(3,700)	)
Depreciation and amortization expense			(1,636)	)		(4,970)	)					(6,606)	)
Share of net income of Frontier			490									490	
Operating income			5,401			12,266						17,667	
Interest expense	(4,217)	)	(825)	)		(802)	)					(5,844)	)
Intercompany interest income (expense)			6,141			(6,141)	)						
Equity earnings	16,428		5,586						(22,014)	)			
Other income	9		434			97						540	
Income tax (expense) benefit			(309)	)		166						(143)	)
Net income	\$	12,220	\$	16,428		\$	5,586		\$	(22,014)	)	\$	12,220

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(1) General and administrative expense is not currently allocated between Guarantor and Non-Guarantor Subsidiaries for financial reporting purposes.

	Statement of Income Six Months Ended June 30, 2006					
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total	
	(in thousands)					
Net operating revenues	\$	76,530	\$	77,492	\$ (4,757 )	\$ 149,265
Operating expenses		(38,882 )		(30,949 )	4,757	(65,074 )
General and administrative expense(1)	(1 )	(11,373 )		(1,213 )		(12,587 )
Merger costs		(3,417 )				(3,417 )
Accelerated long-term incentive plan compensation expense						
Line 63 oil release costs						
Reimbursed general partner transaction costs						
Depreciation and amortization expense		(10,069 )		(10,225 )		(20,294 )
Share of net income of Frontier		873				873
Operating income	(1 )	13,662		35,105		48,766
Interest expense	(17,002 )	(141 )		(2,033 )		(19,176 )
Intercompany interest income (expense)		14,521		(14,521 )		
Equity earnings	50,362	22,941			(73,303 )	
Other income	(302 )	591		446		735
Income tax benefit (expense)		(1,212 )		3,944		2,732
Net income	\$ 33,057	\$ 50,362		\$ 22,941	\$ (73,303 )	\$ 33,057

(1) General and administrative expense is not currently allocated between Guarantor and Non-Guarantor Subsidiaries for financial reporting purposes.

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		Statement of Income														
		Six Months Ended June 30, 2005														
		Parent		Guarantor Subsidiaries		Non-Guarantor Subsidiaries		Consolidating adjustments		Total						
		(in thousands)														
Net operating revenues	\$			\$	34,345			\$	71,202			\$	(3,525)	)	\$	102,022
Operating expenses					(20,290)	)			(30,281)	)			3,525			(47,046)
General and administrative expense(1)					(7,835)	)			(1,037)	)						(8,872)
Accelerated long-term incentive plan compensation expense					(2,675)	)			(440)	)						(3,115)
Line 63 oil release costs						)			(2,000)	)						(2,000)
Reimbursed general partner transaction costs		(893)	)		(914)	)										(1,807)
Depreciation and amortization expense					(3,260)	)			(9,875)	)						(13,135)
Share of net income of Frontier					847											847
Operating income		(893)	)		218				27,569							26,894
Interest expense		(8,295)	)		(1,504)	)			(1,643)	)						(11,442)
Intercompany interest income (expense)					12,412				(12,412)							
Equity earnings		24,812			13,576								(38,388)	)		
Other income		17			600				276							893
Income tax benefit (expense)					(490)	)			(214)	)						(704)
Net income	\$	15,641		\$	24,812		\$	13,576		\$	(38,388)	)	\$	15,641		

(1) General and administrative expense is not currently allocated between Guarantor and Non-Guarantor Subsidiaries for financial reporting purposes.

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	Statement of Cash Flows									
	Six Months Ended June 30, 2006									
	Parent		Guarantor Subsidiaries		Non-Guarantor Subsidiaries		Consolidating Adjustments		Total	
	(in thousands)									
<b>CASH FLOWS FROM OPERATING ACTIVITIES:</b>										
Net income	\$	33,057	\$	50,362	\$	22,941	\$	(73,303)	\$	33,057
Adjustments to reconcile net income to net cash provided by operating activities:										
Equity earnings	(50,362)	)	(22,941)	)			73,303			
Distributions from subsidiaries	45,614		31,523				(77,137)			
Depreciation, amortization and other	1,912		11,100		3,495					16,507
Net changes in operating assets and liabilities	(1,031)	)	(20,899)	)	13,207		1,247			(7,476)
<b>NET CASH PROVIDED BY OPERATING ACTIVITIES</b>	<b>29,190</b>		<b>49,145</b>		<b>39,643</b>		<b>(75,890)</b>			<b>42,088</b>
<b>CASH FLOWS FROM INVESTING ACTIVITIES</b>										
Acquisitions			(2,365)	)						(2,365)
Additions to property, equipment and other	(24)	)	(26,856)	)	(15,476)	)				(42,356)
Additions to pipeline linefill and minimum tank inventory			(8,128)	)	(8,291)	)				(16,419)
Intercompany	(59,000)	)					59,000			
<b>NET CASH USED IN INVESTING ACTIVITIES</b>	<b>(59,024)</b>		<b>(37,349)</b>		<b>(23,767)</b>		<b>59,000</b>			<b>(61,140)</b>
<b>NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES</b>	<b>28,489</b>		<b>(8,985)</b>		<b>(12,690)</b>		<b>16,890</b>			<b>23,704</b>
Effect of translation adjustment					107					107
<b>NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS</b>	<b>(1,345)</b>		<b>2,811</b>		<b>3,293</b>					<b>4,759</b>
CASH AND CASH EQUIVALENTS, beginning of reporting period	4,192		12,484		1,388					18,064
CASH AND CASH EQUIVALENTS, end of reporting period	\$	2,847	\$	15,295	\$	4,681	\$		\$	22,823

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	Statement of Cash Flows Six Months Ended June 30, 2005										
	Parent		Guarantor Subsidiaries		Non-Guarantor Subsidiaries		Consolidating Adjustments		Total		
	(in thousands)										
<b>CASH FLOWS FROM OPERATING ACTIVITIES:</b>											
Net income	\$	15,641	\$	24,812	\$	13,576	\$	(38,388)	\$	15,641	
Adjustments to reconcile net income to net cash provided by operating activities:											
Equity earnings	(24,812	)	(13,576	)			38,388				
Distributions from subsidiaries	30,658		22,784				(53,442	)			
Depreciation, amortization and other	333		6,519		10,224					17,076	
Net changes in operating assets and liabilities	(49	)	6,616		10,047		(3,187	)		13,427	
<b>NET CASH PROVIDED BY OPERATING ACTIVITIES</b>	<b>21,771</b>		<b>47,155</b>		<b>33,847</b>		<b>(56,629</b>	<b>)</b>		<b>46,144</b>	
<b>CASH FLOWS FROM INVESTING ACTIVITIES</b>											
Additions to property, equipment and other			(3,752	)	(6,223	)				(9,975	)
Intercompany	(914	)					914				
<b>NET CASH USED IN INVESTING ACTIVITIES</b>	<b>(914</b>	<b>)</b>	<b>(3,752</b>	<b>)</b>	<b>(6,223</b>	<b>)</b>	<b>914</b>			<b>(9,975</b>	<b>)</b>
<b>NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES</b>	<b>(23,067</b>	<b>)</b>	<b>(40,109</b>	<b>)</b>	<b>(20,014</b>	<b>)</b>	<b>55,641</b>			<b>(27,549</b>	<b>)</b>
Effect of translation adjustment							74			74	
<b>NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS</b>	<b>(2,210</b>	<b>)</b>	<b>3,294</b>		<b>7,610</b>					<b>8,694</b>	
CASH AND CASH EQUIVALENTS, beginning of reporting period	2,713		17,523		3,147					23,383	
CASH AND CASH EQUIVALENTS, end of reporting period	\$	503	\$	20,817	\$	10,757	\$		\$	32,077	



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

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

**Forward-Looking Statements**

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

We caution you that the forward-looking statements in this quarterly report on Form 10-Q are subject to all of the risks and uncertainties, many of which are beyond our control, incident to gathering, transporting, storing, and distributing crude oil and other related products and buying, gathering, blending and selling crude oil or related to our pending merger with Plains All American Pipeline, L.P. For a more detailed description of these and other factors that may affect the forward-looking statements, please read Item 1A Risk Factors contained elsewhere in this report and in our annual report on Form 10-K for the year ended December 31, 2005, Plains All American Pipeline, L.P. joint proxy statement/prospectus on Form S-4 filed with the SEC on July 11, 2006 relating to the merger, as well as our other filings with the SEC. 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. 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 our unaudited condensed consolidated balance sheets, statements of income, statements of cash flows and statement of partners' capital.

This report on Form 10-Q should be read in conjunction with our annual report on Form 10-K for the year ended December 31, 2005.

**Overview**

We are a publicly traded partnership engaged principally in the business of gathering, transporting, storing, and distributing crude oil, refined products and other related products. We generate revenue primarily by transporting such commodities on our pipelines, by leasing capacity in our storage tanks, and by providing other terminaling services. We also buy and sell crude oil, activities that are generally complementary to our other crude oil operations. We conduct our business through two business units, the West Coast Business Unit, which includes activities in California and the Philadelphia, Pennsylvania area,

and the Rocky Mountain Business Unit, which includes activities in five Rocky Mountain states and Alberta, Canada.

We are managed by our general partner, Pacific Energy GP, LP, which is in turn managed by its general partner, Pacific Energy Management LLC ( PEM ). Thus, the officers and Board of Directors of PEM manage the business affairs of Pacific Energy GP, LP and the Partnership. References to our General Partner refer to Pacific Energy GP, LP and/or PEM, as the context indicates.

Our West Coast Business Unit consists of (i) the Line 2000 crude oil pipeline, (ii) the Line 63 crude oil pipeline system, (iii) the Pacific Terminals storage and distribution system, (v) the Pacific Marketing and Transportation ( PMT ) gathering system and crude oil marketing activities, and (iv) the Pacific Atlantic terminals, which were acquired on September 30, 2005. Line 2000 and Line 63 are the only common carrier pipelines delivering crude oil produced in the San Joaquin Valley, in California, and the two primary California Outer Continental Shelf producing fields, Point Arguello and Santa Ynez, to the Los Angeles Basin and Bakersfield. The Pacific Terminals storage and distribution system is a crude oil and dark products storage and pipeline distribution system located in the Los Angeles Basin, and the PMT gathering system is a proprietary gathering operation in the San Joaquin Valley. The Pacific Atlantic terminals consist of the Martinez and Richmond terminals in the San Francisco, California area and the Paulsboro, New Jersey and Philadelphia area terminals. These terminals are refined product (and, in the case of Martinez, crude oil) storage and terminaling facilities. Additionally, we are currently seeking permits for the development of a deepwater petroleum import terminal at Pier 400 in the Port of Los Angeles, which we expect to begin constructing in mid 2007 (see Liquidity and Capital Resources Capital Requirements, Pier 400 for further discussion).

Our Rocky Mountain Business Unit consists of (i) the Rangeland system, (ii) certain undivided interests in the Western Corridor system, (iii) the Salt Lake City Core system, (iv) our interest in Frontier Pipeline Company, and (v) the Rocky Mountain Products Pipeline, which was acquired on September 30, 2005. Our Rocky Mountain crude oil pipeline systems transport crude oil produced in Canada and the U.S. Rocky Mountain region to refineries in Montana, Wyoming, Colorado and Utah. Deliveries are also made to the refining and marketing center of Edmonton, Alberta through our Rangeland system. Deliveries of crude oil are made to refineries directly through our pipelines or indirectly through connections with third-party pipelines. The Rocky Mountain Products Pipeline supplies refined products to the South Dakota, Wyoming and Colorado markets.

#### **Proposed Merger With Plains All American Pipeline, L.P.**

On June 12, 2006, we announced that we had entered into an agreement with Plains All American Pipeline, L.P. ( PAA ), Plains AAP, L.P., a Delaware limited partnership, Plains All American GP LLC ( PAA GP LLC ), PEM, and Pacific Energy GP, LP, pursuant to which we will be merged with and into PAA. In the merger, each of our common unitholders, except LB Pacific, LP ( LB Pacific ), the owner of our General Partner, will receive 0.77 common units of PAA for each Pacific Energy Partners common unit that the unitholder owns. In addition, pursuant to a purchase agreement between LB Pacific and PAA, PAA will acquire from LB Pacific the general partner interest and incentive distribution rights of the Partnership as well as 2,616,250 common units and 7,848,750 subordinated units of Pacific Energy Partners for total consideration of \$700 million in cash. The merger agreement was unanimously approved by the Board of Directors of PEM, as well as by the PAA GP LLC board of directors.

If the proposed transaction is ultimately consummated, the general partner and limited partner interests in us will be extinguished and we will cease to exist as a separate legal entity. Our operating subsidiaries will be directly or indirectly owned by PAA. PAA's management team and board of directors will continue in their current roles and manage the combined company. The merger is expected to close in the fourth quarter of 2006.

Each of us and PAA made customary representations, warranties and covenants in the merger agreement, including covenants restricting our ability to initiate or continue any discussions with any other person with respect to a business combination while the merger is pending or to engage in any of those discussions unless the failure to do so would be reasonably likely to constitute a violation of fiduciary duties. The merger agreement may be terminated by us and/or PAA in specified circumstances, and provides that upon termination of the merger agreement in circumstances involving a competing proposal to acquire us or PAA, the parties are required to pay one another termination fees of up to \$40 million. The merger is subject to the satisfaction or waiver of certain conditions, including, among others:

- the adoption and approval of the merger agreement and the merger by the affirmative vote of the holders of at least a majority of our outstanding common units (excluding common units held by LB Pacific) and at least a majority of our outstanding subordinated units, each voting as a separate class;
- the adoption and approval of the merger agreement and the merger by the affirmative vote of the holders of at least a majority of PAA's outstanding common units, and the approval of the issuance of PAA common units pursuant to the merger agreement by the affirmative vote of the holders of at least a majority of PAA's outstanding common units;
- receipt of required regulatory approvals, including pursuant to the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (which waiting period expired on July 31, 2006, satisfying one of the closing conditions) and approvals of Canadian governmental authorities (of which one governmental authority provided a "no issues" letter and the waiting period has expired), the Federal Communications Commission, the Public Utilities Commission of the state of California and the Public Service Commission of the state of Wyoming;
- the continued effectiveness of PAA's registration statement on Form S-4 to register the PAA common units to be issued in the merger, and the approval for listing on the New York Stock Exchange of such PAA common units;
- the absence of any decree, order, injunction or law that prohibits the merger or makes the merger unlawful; and
- the consummation of the transactions contemplated by the purchase agreement between PAA and LB Pacific.

Each of PAA and LB Pacific made customary representations, warranties and covenants in the purchase agreement. The purchase agreement may be terminated by LB Pacific or PAA upon or after termination of the merger agreement, and may be terminated at any time by the mutual written agreement of LB Pacific and PAA. In addition, the purchase agreement is subject to customary closing conditions, including satisfaction of all conditions specified in the merger agreement.

See "Item 1A Risk Factors" of this Quarterly Report for a discussion of some of the risks related to the merger and the related transactions.

#### **Recent Business Developments**

The Rocky Mountain business unit accomplished several positive initiatives in the first half of 2006. The construction of the initiating facility for synthetic crude oil in Edmonton, Alberta was completed in March 2006, and initial movements of synthetic crude oil began immediately thereafter. This connection provides direct access to synthetic crude oil in Edmonton for delivery through our pipeline systems to U.S. Rocky Mountain refineries. In addition, to facilitate the movement and maintain the quality of synthetic crude oil, three 120,000 barrel tanks were constructed at storage facilities along our pipeline system.

Our subsidiary, Rocky Mountain Pipeline System LLC ( RMPS ), is proceeding with plans to expand its crude oil pipeline system from the terminus of Frontier Pipeline near Evanston, Wyoming to the Salt Lake City, Utah refining complex. A new 16-inch pipeline, which will be 91 miles in length, will be able to transport multiple grades of crude oil in segregated batches and will provide 95,000 barrels per day of capacity to meet increased crude oil demand in Salt Lake City. The project will be constructed in two phases, the first phase estimated to be completed in December 2006, the second phase in the fourth quarter of 2007. The total cost for both phases of the project is expected to be approximately \$77 million and is supported by 10-year transportation agreements that have been executed with four Salt Lake City refiners.

In addition, RMPS signed a transportation agreement with Frontier Oil and Refining Company pursuant to which RMPS will construct a 24-inch crude oil pipeline, approximately 10 miles in length, from Guernsey, Wyoming to RMPS's Fort Laramie, Wyoming tank farm and a 16-inch crude oil pipeline, approximately 85 miles in length, from Fort Laramie to Frontier Oil's Cheyenne refinery, in exchange for Frontier Oil's ten-year firm commitment to ship 35,000 barrels per day on the new pipeline and lease approximately 300,000 barrels of storage capacity at Fort Laramie. The total project cost is estimated to be \$59 million. The project began in the second quarter of 2006 and is expected to be completed in the second quarter of 2007. Initial capacity will be 55,000 barrels per day, which can be expanded to a capacity of 90,000 barrels per day.

In our West Coast business unit, we are currently constructing 450,000 barrels of storage capacity at our Martinez terminal in the San Francisco area, which is expected to be completed in the third quarter of 2006. At our Philadelphia area terminals, we are completing an ethanol expansion project that will enable us to increase our ethanol handling and blending capabilities and increase our marine receipt capabilities. At Pacific Terminals, we are refurbishing 600,000 barrels of black oil storage as well as making infrastructure changes to increase pumping capacity and improve operating efficiencies. The storage tanks are expected to be completed in the second half of 2006. The infrastructure changes will be completed in 2007.

#### **Expected Conversion of Subordinated Units**

In August 2006, we expect that 2,616,250 of the Partnership's subordinated units will convert to common units pursuant to the terms of the Partnership's partnership agreement.

#### **Business Fundamentals**

##### *Pipeline Transportation*

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

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

The tariff rates we charge on Line 2000 and the Line 63 system are regulated by the California Public Utilities Commission ( CPUC ). Tariffs on Line 2000 are established based on market considerations, subject to certain contractual limitations. Tariffs on Line 63, which are cost-of-service based tariffs, are

based upon the costs to operate and maintain the pipeline, as well as charges for the depreciation of the capital investment in the pipeline and the authorized rate of return. The tariff rates charged on our U.S. Rocky Mountain crude oil pipelines are regulated by either the Federal Energy Regulatory Commission ( FERC ) or the Wyoming Public Service Commission ( Wyoming PSC ), generally under a cost-of-service approach. The FERC, Wyoming PSC, and the Colorado Public Utilities Commission each regulate various tariffs on the Rocky Mountain Products Pipeline, which include both cost and market based rates.

Although the tariff rates we charge on the system are regulated, competitive forces may also limit the amount of our filed rates. The FERC tariff rates are generally adjusted, effective July 1 of each year, by the amount of change in the Producer Price Index for Finished Goods, plus 1.3%.

Following are recent tariff rate increases on our pipelines:

- On July 1, 2006, we increased the FERC tariff rates on our U.S. Rocky Mountain crude oil pipeline by 6.1% based on the FERC index adjustment.
- On May 1, 2006, we increased the tariff rates on our Line 2000 by approximately 7.1%.
- Effective August 1, 2005, we implemented a temporary surcharge of \$0.10 per barrel on our Line 63 long-haul tariff rates to recover costs relating to the Line 63 oil release we experienced in 2005, together with other costs incurred or to be incurred as a result of rain-related earth movement and stream erosion.
- On July 1, 2005, we increased the FERC tariff rates on our U.S. Rocky Mountain crude oil pipelines by 3.6% based on the FERC index adjustment.
- On May 1, 2005 we increased the tariff rates on our Line 2000 by approximately 4.8%.

Tariff rate increases on our West Coast pipelines partially mitigate the impact of declining throughput on these pipelines.

The availability of crude oil for transportation on our pipelines is dependent, in part, on the amount of drilling and enhanced recovery activity in the production fields we serve in our West Coast operations and in parts of our Rocky Mountain operations. With the passage of time, production of crude oil in an individual well naturally declines. Although this decline can, in the short term, be offset in whole or in part, by additional drilling or the implementation of recovery enhancement measures, in the San Joaquin Valley and in the California Outer Continental Shelf, total production is generally declining.

In the Rocky Mountains, our pipelines are connected to U.S. and Canadian sources of crude oil. Our Rangeland system in Alberta gives us greater access to significant supplies of Canadian crude oil, including synthetic crude oil, which we believe will replace any long term U.S. Rocky Mountain production declines and meet growing demand in the U.S. Rocky Mountain region. It appears in recent months that production in the U.S. Rocky Mountains may be increasing with the increased amount of natural gas related drilling, which results in increased volumes of crude oil and condensate. We believe, however, that the longer term production of crude oil in the U.S. Rocky Mountains will resume its historical decline.

The Rocky Mountain Products Pipeline acquired in 2005 is a common carrier petroleum products pipeline and terminals network. The system generates revenues through transportation tariffs for volumes of petroleum products it ships. These tariffs vary depending upon where the product originates and where ultimate delivery occurs. The products terminals on the pipeline system also earn revenues by providing additional services.

### *Storage and Terminaling*

We provide storage and terminaling services to refineries in the Los Angeles Basin and San Francisco areas in California and in the Philadelphia, Pennsylvania area. The fundamental items impacting our storage and terminaling revenue are the amount of storage capacity we have under lease, the lease rates for that capacity and the length of each lease.

Demand for crude oil storage capacity tends to be more stable over time and leases for crude oil storage capacity are usually long term (more than one year). Demand for storage capacity for other dark products is less stable than for crude oil storage and varies depending on, among other things, refinery production runs and maintenance activities. Leases for other dark products storage capacity are usually short term (less than one year). One of our business goals is to convert a number of dark products tanks to more flexible crude oil service (which can also continue to accommodate other dark products); and we have recently completed one such tank conversion. While PT's rates are subject to regulation by the CPUC, the CPUC has allowed PT to establish rates based on market conditions through negotiated contracts.

The Martinez, Richmond, Paulsboro and Philadelphia terminals that we purchased in September 2005 are refined product (and, in the case of Martinez, crude oil) storage and terminaling facilities that generate revenues primarily from fees that we charge customers for storage, throughput and other services. Demand for refined products storage capacity, mostly at the Philadelphia area terminals, depends on connections with refineries and petroleum products pipelines owned and operated by third parties.

Demand for refined products storage at our San Francisco area terminals tends to be stable over time as most of our lease contracts are evergreen contracts for a year or more. Additionally, the San Francisco area terminals are not overly reliant on local area refinery production to satisfy the supply of refined products. The San Francisco area terminals receive a significant volume of imported refined products and crude oil into the San Francisco harbor. One of our goals is to increase the storage capacity of our Martinez terminal. We are currently constructing 450,000 barrels of storage, which we expect to place in service in the third quarter of 2006.

The throughput service business of our Philadelphia area terminals, which receive products from local refineries, the U.S. Gulf Coast and New York Harbor, is dependent on the demand for gasoline and other products in the Philadelphia market. In addition, our Philadelphia area terminals provide storage services for local refineries and other marketers.

### *Pipeline Buy/Sell Transportation*

Throughput on our Rangeland system varies with many of the same factors described in *Pipeline Transportation* above.

We have made significant changes to the revenue-generating capability of the Rangeland system, which we acquired in mid-2004, by (i) combining and fully integrating all of our Canadian and U.S. Rocky Mountain pipeline assets under common management, (ii) establishing connections with other pipelines, thereby expanding the throughput of the Rangeland system, and (iii) constructing a pump station and receiving terminal in Edmonton, Alberta, which began operating in March 2006. The volume of throughput originating at our Edmonton, Alberta initiation station will vary with our success in attracting new supplies of synthetic crude oil to our system.

The Rangeland system operates as a proprietary system and, therefore, we take title to the crude oil that is gathered and transported. Pursuant to a transportation service agreement between two of our subsidiaries, Rangeland Marketing Company ( RMC ) and Rangeland Pipeline Partnership, RMC controls the entire capacity of Rangeland pipeline. Customers who wish to transport product on Rangeland pipeline must either: (i) sell product to RMC at an inlet point and repurchase such product at

agreed upon delivery points for the price paid at the inlet to the pipeline plus an established location differential; or (ii) sell product to RMC at the inlet to the pipeline without repurchasing product from RMC.

Virtually all of the pipelines that comprise the Rangeland system are subject to the jurisdiction of the Alberta Energy and Utilities Board ( EUB ). A short segment of the Rangeland system that connects to the Western Corridor system at the U.S.-Canadian border is subject to the jurisdiction of the Canadian National Energy Board ( NEB ). Neither the EUB nor the NEB will generally review rates set by a crude oil pipeline operator unless it receives a complaint relating to transportation rates.

Effective December 1, 2005, we increased the location differentials on the Rangeland pipeline by an average of 6.9%.

### ***Gathering Activities and Marketing Business***

Through our PMT subsidiary, we purchase, gather, and resell crude oil, principally in California's San Joaquin Valley and, to a much lesser extent, in the Rocky Mountain area in the vicinity of our pipelines. In the third quarter of 2005, we began selectively purchasing and reselling crude oil in other areas as well, although this is not a primary focus.

In California, our PMT gathering system is a proprietary intrastate operation that is not regulated by the CPUC or the FERC. It is complementary to our pipeline transportation business. The gathering system effectively extends our pipeline network to capture supplies of crude oil bound for transportation to Los Angeles that might not otherwise be shipped through our pipelines. In the U.S. and Canadian Rocky Mountain area, PMT facilitates transportation on our Canadian and U.S. Rocky Mountain pipelines by purchasing crude oil from Canada for resale in the Rocky Mountain marketplace.

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

### ***Operating Expenses***

Many of our operating expenses, including the cost of field and support personnel, maintenance, control systems, telecommunications, rights-of-way and insurance, are relatively fixed and vary little with changes in throughput. Certain of our costs, however, do vary with throughput, the most material being the cost of power used to operate pump stations along our pipelines or to operate our terminals. Major maintenance costs can vary depending on a particular asset's age and also with regulatory requirements, such as mandatory inspections at defined intervals. Unanticipated costs can include the costs of cleanup of any oil or product release, to the extent they are not covered by insurance, and repairs caused by severe weather as we experienced in California and Alberta, Canada in 2005.

We do not have any employees, except in Canada. Our General Partner provides employees to conduct our U.S. operations. We and our General Partner collectively employ approximately 440 individuals who directly support our operations. We consider employee relations to be good. None of these employees are subject to a collective bargaining agreement, except for eight employees at our Paulsboro, New Jersey, terminal, who are members of USW District 10-286 (Steel Workers), with whom we have a

collective bargaining agreement that will end on October 1, 2009. Our General Partner does not conduct any business other than with respect to the Partnership. All expenses incurred by our General Partner are charged to us.

#### ***Impact of Foreign Exchange Rates***

Assets and liabilities of our Canadian subsidiaries are translated to U.S. dollars using the applicable exchange rate as of the end of each reporting period. Revenues, expenses and cash flow are translated using the average exchange rate during the reporting period. The reported cash flow of our Canadian operations is based on the U.S. dollar equivalent of such amounts measured in Canadian dollars. The results of our Canadian operations and distributions from our Canadian subsidiaries to the Partnership may vary in U.S. dollar terms based on fluctuations in currency exchange rates irrespective of our Canadian subsidiaries' underlying operating results. In addition, the amount of monies we repatriate from Canada will vary with fluctuations in currency exchange rates and may impact the cash available for distribution to our unitholders. We have entered into certain foreign exchange contracts to mitigate currency exchange risks (see Item 3 Quantitative and Qualitative Disclosures about Market Risk ).

#### **Critical Accounting Policies and Estimates**

Our consolidated financial statements are prepared in conformity with accounting principles generally accepted in the United States, which require management to make estimates and assumptions that affect the reported amounts of the assets and liabilities and disclosures of contingent assets and liabilities as of the date of the balance sheet, as well as the reported amounts of revenue and expenses during the reporting period. We routinely make estimates and judgments about the carrying value of our assets and liabilities that are not readily apparent from other sources. Such estimates and judgments are evaluated and modified as necessary on an ongoing basis. We believe that of our significant accounting policies (see Note 2, Significant Accounting Policies, to our consolidated financial statements in our annual report on Form 10-K for the year ended December 31, 2005) and estimates, the following may involve a higher degree of judgment and complexity:

- We routinely apply the provisions of purchase accounting when recording our acquisitions. Application of purchase accounting requires that we estimate the fair value of the individual assets acquired and liabilities assumed (including environmental remediation liabilities). Additionally, we must determine whether an acquisition is to be treated as a purchase of a business or a set of net assets because excess purchase price is only allocated to goodwill in a business combination. Determination of the fair value of the assets involves a number of judgments and estimates. In our major acquisitions to date, we have engaged an outside valuation firm to provide us with an appraisal report, which we utilized in determining the purchase price allocation. The allocation of the purchase price to different asset classes impacts the depreciation and amortization expense we subsequently record. The principal assets we have acquired to date are property, pipelines, storage tanks and equipment, as well as intangible assets such as customer relationships and contractual rights.
- We depreciate and amortize the components of our property and equipment and intangible assets 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 and amortized. When necessary, the assets' useful lives are revised and the impact on depreciation and amortization is adjusted on a prospective basis.
- We accrue an estimate of the undiscounted costs of environmental remediation for work at identified sites where an assessment has indicated it is probable that cleanup costs are or will be required and may be reasonably estimated. In making these estimates, we consider information that



is currently available, existing technology, enacted laws and regulations, and our estimates of the timing of the required remedial actions. We may use outside environmental consultants to assist us in making these estimates. We also are required to estimate the amount of any probable recoveries, including insurance recoveries. In addition, generally accepted accounting principles require us to establish liabilities for the costs of asset retirement obligations when a legal or contractual obligation exists to dispose of or restore an asset upon its retirement and the timing and cost of such work is reasonably estimable. We will record such liabilities only when such timing and costs are reasonably determinable.

- From time to time, a shipper or group of shippers or regulatory body may initiate regulatory proceedings or other actions challenging the tariffs we charge or have charged. In such cases, we assess the proceeding on an ongoing basis as to its likely outcome in order to determine whether to accrue for a future expense. We use outside regulatory lawyers and financial experts to assist us in these assessments.
- Our inventory of crude oil for our PMT gathering operations and marketing business, our Canadian operations, any inventory earned through our tariffs for the transportation of crude oil in our common carrier pipelines and any inventory of refined products at our terminals is carried in our accounts at the lower of cost or market value, unless it is hedged, in which case it is carried at market. On any hedged portion, we are exposed to the potential that our hedges may not be perfectly effective. On any unhedged portion, we are exposed to the potential for a write-down to market value. To the extent we owe our customers crude oil or refined products, we are exposed to the potential of additional costs in the event market prices increase.

#### **Results of Operations**

Internally, in our analysis of operating results, we consider the impact of unusual items that we believe affect comparability between periods. We also believe that providing a discussion and analysis of our results that is comparable year over year provides a more accurate and thorough analysis of our results of operations. We have provided a reconciliation of net income to the results of our operations, excluding those unusual items, in our analyses below. Following is a description of each of the unusual items that impacted the results of our operations.

*Merger costs.* On June 12, 2006, we announced that we had entered into a merger agreement with *Plains All American Pipeline, L.P.*, pursuant to which we will be merged into PAA. For the three and six months ended June 30, 2006, we incurred \$3.4 million in investment banking fees, legal fees and other transaction costs directly related to the merger.

*Tax rate adjustments to net deferred tax liabilities.* During the quarter ended June 30, 2006, the Canadian and Alberta governments enacted legislation that will reduce federal and provincial income taxes. We adjusted our estimate of future income tax rates in our estimates of deferred tax assets and liabilities and recognized a \$4.6 million deferred tax benefit during the three months ended June 30, 2006.

*Line 63 oil release.* On March 23, 2005, a release of approximately 3,400 barrels of crude oil occurred on PPS's Line 63 as a result of a landslide caused by heavy rainfall in northern Los Angeles County. As a result of the release, we recorded \$2.0 million net oil release costs in the first quarter of 2005, consisting of what we now estimate to be \$25.5 million of total costs relating to the release, net of insurance recoveries of \$17.7 million to date and accrued future insurance recoveries of \$5.8 million at June 30, 2006.

*Accelerated long-term incentive plan compensation expense.* On March 3, 2005, in connection with the change in control of our General Partner, all restricted units then outstanding under the Long-term Incentive Plan immediately vested. As a result, we recorded a \$3.1 million compensation expense in the first quarter of 2005.

*Reimbursed general partner transaction costs.* Pursuant to an agreement entered into in connection with the sale of The Anschutz Corporation's (the owner of our General Partner before March 3, 2005) interest in us, LB Pacific, LP and The Anschutz Corporation reimbursed us \$2.4 million for the cost incurred in connection with a consent solicitation prepared and delivered to the holders of our 7 $\frac{1}{8}$ % senior notes to approve certain amendments to the governing indenture and for severance and other costs incurred in connection with the sale of our General Partner. In accordance with generally accepted accounting principles, we recorded \$0.6 million as capitalized deferred financing costs and \$1.8 million as an expense, both in the first quarter of 2005. The reimbursements were recorded as a capital contribution to the Partnership by our General Partner.

***Three Months Ended June 30, 2006 Compared to Three Months Ended June 30, 2005***

***Summary***

Net income for the three months ended June 30, 2006 was \$21.4 million, or \$0.54 per diluted limited partner unit, compared to \$12.2 million, or \$0.40 per diluted limited partner unit, for the three months ended June 30, 2005.

Net income for the three months ended June 30, 2006 includes a full quarter of operations of the Pacific Atlantic terminals and the Rocky Mountain Products Pipeline, which were acquired on September 30, 2005

Following is a reconciliation of net income to the results of our operations, excluding the unusual items mentioned above:

	<b>Three Months Ended June 30,</b>			
	<b>2006</b>	<b>2005</b>	<b>Change</b>	<b>Percent</b>
	<b>(In thousands)</b>			
Net income	\$ 21,443	\$ 12,220	\$ 9,223	75 %
Add: Merger costs	3,417		3,417	
Less: Tax rate adjustments to deferred tax liability	(4,560 )		(4,560 )	
	\$ 20,300	\$ 12,220	\$ 8,080	66 %
Diluted weighted average limited partner units	39,314	29,742	9,572	32 %

The improvement in the results of operations, excluding the effect of the unusual items mentioned above, reflects the benefit of (i) the operations of Pacific Atlantic terminals and the Rocky Mountain Products Pipeline acquired on September 30, 2005, (ii) increased margins in our gathering and marketing business, (iii) higher operating income on our West Coast pipelines due to increased deliveries to Bakersfield, California refineries and lower repair and maintenance costs, and (iv) higher revenues on the Rangeland pipeline system because of favorable margins and higher volumes. These increases were partially offset by higher interest expense primarily due to higher debt levels, and increased general and administrative costs. There were 39.3 million weighted average limited partner units outstanding in the three months ended June 30, 2006, approximately 32% more limited partner units than the 29.7 million weighted average units outstanding in the three months ended June 30, 2005. The higher debt levels and increased number of units reflect the funding of the acquisition of the Pacific Atlantic terminals and the Rocky Mountain Products Pipeline.

**Segment Information**

The following is a discussion of segment operating income, which does not include general and administrative expenses, merger costs, accelerated long-term incentive compensation plan expense and reimbursed general partner transaction costs, as these items are not allocated to the West Coast and Rocky Mountain business units.

West Coast	Three Months Ended June 30,		Change	Percent
	2006 (In thousands)	2005		
Operating income	\$ 21,988	\$ 12,405	\$ 9,583	77 %
Operating data:				
Pipeline throughput (bpd)	108.2	120.0	(11.8 )	(10 )%

West Coast operating income was higher in 2006 due to (i) the result of operations of the Pacific Atlantic terminals, which were acquired in September 2005, (ii) higher pipeline transportation income, and (iii) higher margins in our gathering and marketing business. Although West Coast pipeline volumes were approximately 10% lower than in 2005, this decline was more than offset by tariff increases on Line 2000 and Line 63, the absence of \$1.4 million of rain related pipeline repair expenses incurred in the second quarter of 2005, and a substantial increase in deliveries to Bakersfield area refineries. Reduced volumes on our West Coast pipelines were caused by the natural production decline of San Joaquin Valley crude and Outer Continental Shelf crude oil and a shift of light crude being transported north to the San Francisco Bay area, which had previously been transported south on our pipelines to the Los Angeles area.

Crude oil marketing income was significantly higher in the second quarter of 2006 than the corresponding period in 2005. Favorable margins, crude oil contracts acquired on July 1, 2005, and increased crude oil volumes in the 2006 quarter contributed to the improvement.

Rocky Mountains	Three Months Ended June 30,		Change	Percent
	2006 (In thousands)	2005		
Operating income	\$ 15,354	\$ 8,962	\$ 6,392	71 %
Operating data (bpd):				
Rangeland pipeline system:				
Sundre North	21.5	23.1	(1.6 )	(7 )%
Sundre South	44.2	39.7	4.5	11
Western Corridor system	27.9	22.2	5.7	26
Salt Lake City Core system	125.2	124.4	0.8	1
Frontier pipeline	45.2	51.3	(6.1 )	(12 )
Rocky Mountain Products Pipeline	60.1		60.1	

For the three months ended June 30, 2006, operating income was \$15.4 million, compared to \$9.0 million for the three months ended June 30, 2005. The increase was primarily due to increased volumes on the Rangeland Pipeline, Western Corridor and Salt Lake City Core systems, income contribution from the Rocky Mountain Products Pipeline, which was acquired on September 30, 2005, and favorable crude oil marketing margins.

In March 2006, we completed the construction of our Edmonton, Alberta initiating terminal, which provides direct access to synthetic crude oil for delivery through our pipeline systems to U.S. Rocky Mountain refineries. During the second quarter of 2006, construction was also completed on additional tankage along this corridor to facilitate the movement of the synthetic crude oil. The transportation of synthetic crude oil was significantly lower than expected in the second quarter of 2006 due to maintenance

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shutdowns at two major synthetic crude oil facilities in Alberta. However, with these facilities now ramping up to full capacity, synthetic crude oil movements in the third quarter of 2006 are expected to increase.

### *Statement of Income Discussion and Analysis*

Revenues	Three months ended June 30,		Change	Percent
	2006 (In thousands)	2005		
Pipeline transportation revenue	\$ 34,800	\$ 27,747	\$ 7,053	25 %
Storage and terminaling revenue	21,867	10,870	10,997	101
Pipeline buy/sell transportation revenue	11,427	8,116	3,311	41
Crude oil sales, net of purchases:				
Crude oil sales	364,310	128,484	235,826	184
Crude oil purchases	(353,590 )	(122,442 )	231,148	189
Crude oil sales, net of purchases	10,720	6,042	4,678	77
Net revenue	\$ 78,814	\$ 52,775	\$ 26,039	49 %

We experienced higher pipeline transportation revenues on most of our pipelines. Pipeline transportation revenues in 2006 include revenues from our Rocky Mountain Products Pipeline, which was acquired in September 2005, and trucking revenues from the purchase of a crude oil trucking business in January 2006. In our West Coast business unit, the impact of lower long-haul pipeline transportation volumes was offset by higher tariff rates and increased deliveries to Bakersfield area refineries.

Storage and terminaling revenue increased in 2006 primarily because of the acquisition of the Pacific Atlantic terminals in September 2005.

Pipeline buy/sell transportation revenues increased due to favorable marketing margins and because we began transporting synthetic crude oil from Edmonton to the U.S. Rocky Mountain region after the completion of our initiating facility in Edmonton, Alberta in March 2006.

Crude oil sales net of purchases increased because of the purchase of crude oil contracts that commenced in July 2005, and higher overall margins. Higher crude oil prices increased gross sales and purchases.

Expenses	Three Months ended June 30,		Change	Percent
	2006 (In thousands)	2005		
Operating expenses	\$ 31,655	\$ 25,292	\$ 6,363	25 %
General and administrative expense	5,714	3,700	2,014	54
Depreciation and amortization	10,292	6,606	3,686	56
Merger costs	3,417		3,417	
	\$ 51,078	\$ 35,598	\$ 15,480	43 %

Merger costs are discussed above.

The increase in operating expenses was related primarily to the incremental operations of the Pacific Atlantic terminals and the Rocky Mountain Products Pipeline, which were acquired in September 2005. Operating expenses were also higher as a result of higher power costs.

The increase in general and administrative expense was primarily associated with the support of newly acquired assets, professional fees and \$0.4 million of costs for the LB Pacific, LP option plan, which we are required by generally accepted accounting principles to record as our expense even though the plan is funded by LB Pacific, LP and not by the Partnership.

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The increase in depreciation and amortization includes \$3.2 million for depreciation on the Rocky Mountain Products Pipeline and the Pacific Atlantic terminals acquired in September 2005.

Other Income and Expense	Three Months ended June 30,		Change	Percent
	2006 (In thousands)	2005		
Share of net income of Frontier	\$ 475	\$ 490	\$ (15 )	(3 )%
Interest expense	\$ 10,088	\$ 5,844	\$ 4,244	73
Other income	\$ 292	\$ 540	\$ (248 )	(46 )
Income tax expense (benefit)	\$ (3,028 )	\$ 143	\$ (3,171 )	(2,217 )

Our share of Frontier's net income was unchanged as the impact of lower pipeline volumes in 2006 was offset by reduced expenses.

The increase in interest expense was due to additional borrowings incurred to partially fund the acquisition of the Pacific Atlantic terminals and the Rocky Mountain Products Pipeline, and higher interest rates. Our weighted average borrowings during the three months ended June 30, 2006 were \$622 million compared to \$366 million in the corresponding period in 2005. Floating interest rates were higher in 2006. Our weighted average interest rate was 7.0% for the period ended June 30, 2006, compared to a weighted average interest rate of 6.4% for the corresponding period in 2005. Capitalized interest was \$0.9 million and \$0.2 million for the three months ended June 30, 2006 and 2005, respectively.

Other income of \$0.3 million for the period ended June 30, 2006 was \$0.2 million lower than the corresponding period in 2005.

Income tax expense is a function of the income of our Canadian subsidiaries, which are taxable entities in Canada. In addition, certain kinds of repatriation of funds into the U.S. are subject to Canadian withholding tax. During the quarter ended June 30, 2006, the Canadian and Alberta governments enacted legislation that will reduce federal and provincial income taxes. We adjusted our estimate of future income tax rates in our estimates of deferred tax assets and liabilities and recognized \$4.6 million of net deferred tax benefit in earnings during the three months ended June 30, 2006. This adjustment in deferred taxes was partially offset by higher current income tax expense as a result of higher income from our Canadian subsidiaries.

### *Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005*

#### *Summary*

Net income for the six months ended June 30, 2006 was \$33.1 million, or \$0.83 per diluted limited partner unit, compared to \$15.6 million, or \$0.58 per diluted limited partner unit, for the six months ended June 30, 2005.

Net income for the six months ended June 30, 2006 includes six months of operations of the Pacific Atlantic terminals and the Rocky Mountain Products Pipeline, which were acquired on September 30, 2005.

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Following is a reconciliation of net income to the results of our operations, excluding the unusual items mentioned above:

	Six Months Ended June 30,		Change	Percent
	2006	2005		
	(In thousands)			
Net income	\$ 33,057	\$ 15,641	\$ 17,416	111 %
Add: Merger costs	3,417		3,417	
Line 63 oil release costs		2,000	(2,000 )	
Accelerated long-term incentive compensation expense		3,115	(3,115 )	
Reimbursed general partner transaction costs		1,807	(1,807 )	
Less: Tax rate adjustments to deferred tax liability	(4,560 )		(4,560 )	
	\$ 31,914	\$ 22,563	\$ 9,351	41 %
Diluted weighted average limited partner units	39,322	29,708	9,614	32 %

The improvement in the results of operations, excluding the effect of the unusual items mentioned above, reflects the benefit of (i) the operations of the Pacific Atlantic terminals and the Rocky Mountain Products Pipeline acquired in September 2005; (ii) increased margins in our gathering and marketing business, (iii) higher revenues on the Rangeland Pipeline system because of higher volumes moving south from Alberta, Canada to the U.S. border and higher margins, and (iv) higher pipeline transportation income in our West Coast business unit due to increased Bakersfield refinery deliveries and lower repair and maintenance costs. These increases were partially offset by higher interest expense primarily due to higher debt levels and increased general and administrative costs. There were 39.3 million weighted average limited partner units outstanding in the six months ended June 30, 2006, approximately 32% more limited partner units than the 29.7 million weighted average units outstanding in the six months ended June 30, 2005, due to the sale of additional common units to partially fund the acquisition of the Pacific Atlantic terminals and the Rocky Mountain Products Pipeline.

**Segment Information**

The following is a discussion of segment operating income. Segment operating income does not include general and administrative expenses, merger costs, accelerated long-term incentive compensation plan expense and reimbursed general partner transaction costs, as these items are not allocated to the West Coast and Rocky Mountain business units.

West Coast	Six Months Ended June 30,		Change	Percent
	2006	2005		
	(In thousands)			
Operating income	\$ 39,617	\$ 22,149	\$ 17,468	79 %
Add: Line 63 oil release cost		2,000	(2,000 )	
	\$ 39,617	\$ 24,149	\$ 15,468	64 %
Operating data:				
Pipeline throughput (bpd)	113.4	129.2	(15.8 )	(12 )%

West Coast operating income was higher in 2006 due to (i) the result of operations of the Pacific Atlantic terminals, which were acquired in September 2005, (ii) higher pipeline and transportation income due to higher tariff rates and increased deliveries to the Bakersfield area refineries, and lower repair and maintenance costs, and (iii) higher margins in our gathering and marketing business, which were above average in 2006 and below average in 2005. Margins were below average in 2005 in our gathering and marketing business due to pricing pressures from steeply discounted crude oil imports, and an unfavorable

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purchase contract that expired on March 31, 2005. In addition, crude oil contracts acquired on July 1, 2005 benefited our gathering and marketing business in the first half of 2006. Partially offsetting these increases were lower tank utilization in our PT storage and distribution operations, which was lower than in the first half of 2005. The high utilization in 2005 was the result of extensive refinery maintenance and resultant demand for black oil storage in the first half of 2005. Although West Coast long haul pipeline volumes were approximately 12% lower than in 2005, this decline was offset by tariff increases on Line 2000 and Line 63, and increased deliveries to the Bakersfield area. Reduced volumes on our West Coast pipelines were caused by lower San Joaquin Valley and Outer Continental Shelf production, third-party production problems, a shift of light crude being transported north to the San Francisco Bay area, which had previously been transported south on our pipelines to the Los Angeles area, and San Francisco area refinery turnarounds in the first half of 2005. We benefited from those turnarounds in 2005 because they increased volumes transported by us south to Los Angeles area refineries. In addition, in 2005 we incurred \$1.4 million of rain related repairs.

Rocky Mountains	Six Months ended June 30,		Change	Percent
	2006	2005		
	(In thousands)			
Operating income	\$ 25,153	\$ 18,539	\$ 6,614	36 %
Operating data (bpd):				
Rangeland pipeline system:				
Sundre North	23.1	22.2	0.9	4 %
Sundre South	42.5	43.9	(1.4 )	(3 )
Western Corridor system	26.2	22.4	3.8	17
Salt Lake City Core system	124.5	116.7	7.8	7
Frontier pipeline	46.7	44.8	1.9	4
Rocky Mountain Products Pipeline	60.8		60.8	

For the six months ended June 30, 2006, operating income was \$25.2 million compared to \$18.5 million for the six months ended June 30, 2005. The increase included the results of operations of the Rocky Mountain Products Pipeline, which was acquired in September 2006. We increased location differentials and experienced increased marketing margins on our Rangeland pipelines and higher volumes and tariffs on our U.S. Rocky Mountain pipelines.

*Statement of Income Discussion and Analysis*

Revenues	Six months ended June 30,		Change	Percent
	2006	2005		
	(In thousands)			
Pipeline transportation revenue	\$ 68,657	\$ 55,784	\$ 12,873	23 %
Storage and terminaling revenue	41,953	21,192	20,761	98
Pipeline buy/sell transportation revenue	21,126	17,222	3,904	23
Crude oil sales, net of purchases:				
Crude oil sales	627,438	244,657	382,781	156
Crude oil purchases	(609,909 )	(236,833 )	(373,076 )	158
Crude oil sales, net of purchases	17,529	7,824	9,705	124
Net revenue	\$ 149,265	\$ 102,022	\$ 47,243	46 %

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We experienced higher pipeline transportation revenues on most of our pipelines. Pipeline transportation revenues in 2006 include revenues from our Rocky Mountain Products Pipeline, which was acquired in September 2005. In the Rocky Mountains, we experienced higher volumes and tariffs and increased trucking revenues from the purchase of a crude oil trucking business in January 2006. In our West Coast business unit, the impact of lower long haul pipeline transportation volumes was offset by higher tariffs and increased deliveries to Bakersfield area refineries.

Storage and terminaling revenues increased in 2006 primarily because of the acquisition of the Pacific Atlantic terminals in September 2005. This increase was partially offset by a decline in tank utilization on our Pacific Terminals storage and distribution system.

Pipeline buy/sell transportation revenues increased because of increased location differentials and marketing margins.

Crude oil sales net of purchases increased because of the purchase of crude oil contracts in July 2005 and higher margins. Margins were above average in 2006 and below average in 2005 in our gathering and marketing business for reasons described above. Higher crude oil prices increased gross sales and purchases.

Expenses	Six Months ended June 30,		Change	Percent
	2006 (In thousands)	2005		
Operating expenses	\$ 65,074	\$ 47,046	\$ 18,028	38 %
General and administrative expense	12,587	8,872	3,715	42
Depreciation and amortization	20,294	13,135	7,159	55
Merger costs	3,417		3,417	
Accelerated long-term incentive plan compensation expense		3,115	(3,115 )	
Line 63 oil release costs		2,000	(2,000 )	
Reimbursed general partner transaction costs		1,807	(1,807 )	
	\$ 101,372	\$ 75,975	\$ 25,397	33 %

Merger costs, accelerated long-term incentive plan compensation expense, Line 63 oil release costs and reimbursed general partner transaction costs are discussed above.

The increase in operating expense was related primarily to the acquisition of the Rocky Mountain Products Pipeline and the Pacific Atlantic terminals in September 2005. Operating expenses were also higher as a result of higher power costs.

The increase in general and administrative expense was primarily associated with the support of newly acquired assets, professional fees, and \$0.9 million in costs for a new LB Pacific, LP option plan, which are required by generally accepted accounting principles to be recorded as our expense even though the plan is funded by LB Pacific, LP and not by the limited Partnership.

The increase in depreciation and amortization includes \$6.4 million for depreciation on the Pacific Atlantic terminals and the Rocky Mountain Products Pipeline.

Other Income and Expense	Six Months ended June 30,		Change	Percent
	2006 (In thousands)	2005		
Share of net income of Frontier	\$ 873	\$ 847	\$ 26	3 %
Interest expense	\$ 19,176	\$ 11,442	\$ 7,734	68
Other income	\$ 735	\$ 893	\$ (158 )	(18 )
Income tax expense (benefit)	\$ (2,732 )	\$ 704	\$ (3,436 )	(488 )



The increase in our share of Frontier's net income was mainly attributable to increased pipeline volumes in the six months ended June 30, 2006, partially offset by increased operating expenses.

The increase in interest expense was primarily due to borrowings incurred to partially fund the acquisition of the Rocky Mountain Products Pipeline and the Pacific Atlantic terminals. Our weighted average borrowings during the six months ended June 30, 2006 were \$600 million, compared to \$362 million in the corresponding period in 2005. In addition, floating interest rates were higher in 2006. We realized a weighted average interest rate of 6.9% for the six months ended June 30, 2006, compared to a weighted average interest rate of 6.3% for the corresponding period in 2005. Capitalized interest was \$1.7 million and \$0.3 million for the six months ended June 30, 2006 and 2005, respectively.

Other income of \$0.7 million for the period ended June 30, 2006 was \$0.2 million lower than the corresponding period in 2005.

Income tax expense is a function of the income of our Canadian subsidiaries, which are taxable entities in Canada. In addition, certain kinds of repatriation of funds into the U.S. are subject to Canadian withholding tax. During the six months ended June 30, 2006, the Canadian and Alberta governments enacted legislation that will reduce federal and provincial income taxes. We adjusted our estimate of future income tax rates in our estimates of deferred tax assets and liabilities and recognized a \$4.6 million deferred tax benefit during the six months ended June 30, 2006. This adjustment in deferred taxes was partially offset by higher current income tax expense as a result of greater income from our Canadian subsidiaries.

### **Liquidity and Capital Resources**

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

We intend to finance our future acquisitions and development projects, including our Pier 400 project, with issuances of debt and equity securities. We expect to maintain a debt to total capitalization ratio of approximately 50% over time.

On December 23, 2005, we and certain of our subsidiaries 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 market conditions and our needs, of up to \$1.0 billion of common units of the Partnership and debt securities of both the Partnership and certain subsidiaries. This shelf registration statement was to allow us to finance new acquisitions and new projects such as our Pier 400 Project.

We received approval from the CPUC to dismantle certain idle PT assets and sell the underlying land, which has an estimated value of approximately \$10 million. We expect to sell these various parcels of land in 2006.

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

The merger agreement contains covenants which limit us in the conduct of our business, including but not limited to the following:

- We are limited to an aggregate of \$150 million from the issuance of equity securities pending completion of the merger.
- Our quarterly distributions are limited to \$0.5675 per unit.
- We are limited on the size of any potential acquisition and new project development.

***Operating, Investing and Financing Activities***

	Six Months Ended June 30, 2006 (In thousands)	2005	Change
Net cash provided by operating activities	\$ 42,088	\$ 46,144	\$ (4,056 )
Net cash used in investing activities	(61,140 )	(9,975 )	(51,165 )
Net cash provided by (used in) financing activities	23,704	(27,549 )	51,253

***Net cash provided by operating activities***

Net cash from operating activities in 2006 was positively impacted by an increase in net income due to the operations of the Rocky Mountain Products Pipeline and the Pacific Atlantic terminals, which were acquired on September 30, 2005, higher pipeline transportation revenue, and increased margins in our gathering and marketing business. Offsetting these increases were a \$4.6 million non-cash tax rate adjustment for deferred taxes and an increase in the quantity of crude oil stored for our own account because of contango market conditions (when oil prices for future deliveries are higher than for current deliveries). In a contango market we store crude oil purchased at lower prices in the current month for delivery at higher prices in future months, and protect such margin through hedging. As such, cash provided by operating activities was adversely affected by the change in inventory and in crude oil sales receivable net of crude oil purchase liability reflecting the timing of the inventory build-up.

***Net cash used in investing activities***

We had capital expenditures of \$42.5 million for the six months ended June 30, 2006, which include (i) \$26.0 million for expansion projects (see Capital Requirements below for a list of our projects and forecasted expansion expenditures in 2006), (ii) \$9.0 million for the development of the Pier 400 project, (iii) \$2.6 million related to sustaining capital projects and (iv) \$4.9 million of transition projects related to the Edmonton initiation station as well as transition of the Rocky Mountain Products Pipeline and the Pacific Atlantic terminals to our operations. Additionally, we paid \$18.1 million for pipeline linefill in connection with the start-up of our Edmonton initiation station and \$2.3 million for a trucking business in the U.S. Rocky Mountains.

Capital expenditures for the six months ended June 30, 2005 were \$9.9 million, of which \$0.8 million related to sustaining capital projects, \$3.2 million related to transition projects, \$3.7 million related to expansion and \$2.2 million was for the development of the Pier 400 Project.

***Net cash provided by (used in) financing activities***

Net cash provided by financing activities for the six months ended June 30, 2006 includes net borrowings of \$69.5 million under our senior secured credit facility, which was used primarily to fund our expansion capital projects and pipeline linefill as describe above. We also distributed \$45.6 million to our limited partners and General Partner during the six months ended June 30, 2006.

Cash provided by financing activities for the six months ended June 30, 2005 include distributions of \$30.7 million that were made to the limited partners and the General Partner. Additionally, our General Partner contributed \$2.4 million to reimburse us for certain costs incurred in connection with the sale of the The Anschutz Corporation's interest in us. We also received \$2.0 million in net proceeds from our credit facilities in the six months ended June 30, 2005.

**Capital Requirements**

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

- sustaining capital expenditures to replace partially or fully depreciated assets in order to maintain the existing operating capacity or efficiency of our assets and extend their useful lives;
- transitional capital expenditures to integrate acquired assets into our existing operations; and
- expansion capital expenditures to expand or increase the efficiency of the existing operating capacity of our assets, whether through construction or acquisition, such as placing new storage tanks in service to increase our storage capabilities and revenue, or adding new pump stations or pipeline connections to increase our transportation throughput and revenue.

We expect to invest approximately \$162 million in total capital expenditures in 2006, with approximately \$148 million of that total on expansion projects. Our estimated 2006 expansion capital spending includes the following notable projects.

2006 Forecast Expansion Capital Expenditures	Estimated to be incurred in 2006 (in millions)
Phase I of Salt Lake City expansion, and beginning of phase II	\$ 44
2006 portion of the construction of a new pipeline to Cheyenne, Wyoming	31
Capital projects associated with the new refined products assets	25
Completion of permitting process, engineering and other project development cost for the Pier 400 project	19
Reactivation of storage tanks and infrastructure enhancements at PT	13
Completion of storage tanks for the Rangeland System and Western Corridor pipeline to facilitate the transportation of synthetic crude oil	6
Other	10
Total	\$ 148

In addition to the expansion projects above, we expect to incur \$7 million for transitional capital expenditures and \$7 million for sustaining capital expenditures during 2006.

**Pier 400**

We continue our efforts to develop a deepwater petroleum import terminal at Pier 400 and Terminal Island in the Port of Los Angeles ( POLA ) to handle marine receipts of crude oil and refinery feedstocks. As currently envisioned, the project would include a deep water berth, high capacity transfer infrastructure and storage tanks, with a pipeline distribution system that will connect to various customers, some directly, and some through our Pacific Terminals storage and distribution system. We would construct the storage tanks and transfer infrastructure, including a large diameter pipeline system for receiving bulk petroleum liquids from marine vessels. If successful, this project will allow us to increase our participation in the Los Angeles basin marine import business, which is growing as a result of a decline in both California production and imports from Alaska.

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We have entered into agreements with ConocoPhillips and two subsidiaries of Valero Energy Corporation that provide long term customer commitments to off-load a total of 140,000 bpd of crude oil at the Pier 400 dock. The ConocoPhillips and Valero agreements are subject to satisfaction of various conditions, such as the achievement of various progress milestones, financing, continued economic viability, and completion of other ancillary agreements related to the project. We are negotiating similar long term off-loading agreements with other potential customers.

In the first quarter of 2006, we completed an updated cost estimate for the project. We are estimating that Pier 400 will cost approximately \$315 million, which is subject to change depending on various factors, including: (i) the final scope of the project and the requirements imposed through the permitting process; and (ii) changes in construction costs. This cost estimate now assumes the construction of 4.0 million barrels of storage. We are in the process of securing the environmental and other permits that will be required for the Pier 400 Project from a variety of governmental agencies, including the Board of Harbor Commissioners, the South Coast Air Quality Management District, various agencies of the City of Los Angeles, the Los Angeles City Council and the U.S. Army Corps of Engineers. Due to the complexity of the environmental review process, we now expect to have the necessary permits in mid 2007.

Final construction of the Pier 400 Project is subject to the completion of a land lease agreement with the POLA, receipt of environmental and other approvals, securing additional customer commitments, updating engineering and project cost estimates, ongoing feasibility evaluation, and financing. We now expect construction of the Pier 400 terminal to be completed and the facility to be placed in service in the first quarter of 2009.

We have capitalized \$27.3 million on the Pier 400 project through June 30, 2006, including \$9.0 million for the six months ended June 30, 2006. We anticipate funding the remaining permitting and pre-construction costs in 2006 from our revolving credit facility. Construction of the Pier 400 terminal is expected to be financed through a combination of debt and proceeds from the issuance of additional partnership units, including common units.

### *Debt Obligations*

Our debt obligations include:

	<b>June 30, 2006 (in thousands)</b>	<b>December 31, 2005</b>
\$400 million senior secured credit facility, bearing interest at 5.8% on June 30, 2006, due September 30, 2010	\$ 213,058	\$ 140,751
7½% senior notes, due June 2014, net of unamortized discount of \$3,715 and \$3,882 and including fair value (decreases) increases of \$(2,488) and \$567, respectively	243,796	246,684
6¼% senior notes, due September 2015, net of unamortized discount of \$753 and \$782, respectively	174,248	174,218
Future payment for MAPL assets, net of unamortized discount of \$218 and \$309, respectively	4,266	3,979
<b>Total long-term debt</b>	<b>\$ 635,368</b>	<b>\$ 565,632</b>

As of June 30, 2006, \$86 million of undrawn credit was available under the senior secured revolving credit facility. With the consent of the administrative agent under the revolving credit facility, we can increase credit availability up to an additional \$75 million, based upon pro-forma EBITDA from future acquisitions.

### Off-Balance Sheet Arrangements

As of June 30, 2006, we had standby letters of credit outstanding of \$25.8 million for securing crude oil purchases and the MAPL note, both of which are reflected as liabilities on the balance sheet.

### Accounting Pronouncements

In December 2005, the Financial Accounting Standards Board ( FASB ) issued Statement of Financial Accounting Standards No. 123 (revised December 2005), *Share-Based Payment (SFAS 123R)*. This Statement is a revision of SFAS No. 123. SFAS 123R establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services. SFAS 123R is effective for the Partnership as of the beginning of the first annual reporting period that begins after June 15, 2006. The adoption of SFAS 123R on January 1, 2006 did not have a material impact on our consolidated financial statements.

In September 2005, the Emerging Issues Task Force ( EITF ) issued Issue No. 04-13 ( EITF 04-13 ), *Accounting for Purchases and Sales of Inventory with the Same Counterparty*. The issues addressed by the EITF are (i) the circumstances under which two or more exchange transactions involving inventory with the same counterparty should be viewed as a single exchange transaction for the purposes of evaluating the effect of APB No. 29; and (ii) whether there are circumstances under which nonmonetary exchanges of inventory within the same line of business should be recognized at fair value. EITF 04-13 is effective for new arrangements entered into in the reporting periods beginning after March 15, 2006, and to all inventory transactions that are completed after December 15, 2006, for arrangements entered into prior to March 15, 2006. The adoption of EITF 04-13 did not have a material impact on our consolidated financial statements.

In June 2006, the FASB issued FASB Interpretation No. 48 ( FIN 48 ), *Accounting for Uncertainty in Income Taxes*. This Interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. This Interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. FIN 48 will apply to the Partnership's Canadian subsidiaries, which are taxable entities in Canada, but not to the Partnership. The Partnership is in the process of determining the impact of FIN 48 on its financial statements, but does not expect it to have a material impact on its financial statements. FIN 48 is effective for the Partnership as of the beginning of the first fiscal year beginning after January 1, 2007.

In June 2006, the EITF issued Issue No. 06-3 ( EITF 06-3 ), *How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation)*. The issues addressed by the EITF are (i) Whether the scope of this Issue should include (a) all nondiscretionary amounts assessed by governmental authorities, (b) all nondiscretionary amounts assessed by governmental authorities in connection with a transaction with a customer, or (c) only sales, use, and value added taxes and (ii) How taxes assessed by a governmental authority within the scope of this Issue (Issue 1) should be presented in the income statement (that is, gross versus net presentation). EITF 06-3 is effective for interim and annual financial periods beginning after December 15, 2006. The Partnership is in the process of determining the impact of EITF 06-3 on its financial statements, but does not expect it to have a material impact on its 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 commodity price risk, interest rate risk and currency exchange risk. We use derivative financial instruments to reduce our exposure to adverse fluctuations in commodity prices, interest rates and foreign exchange rates. We formally designate and document the financial

instruments as a hedge of a specific underlying exposure, as well as the risk management objectives and strategies for undertaking the hedge transactions. We formally assesses, both at the inception and at least quarterly thereafter, whether the financial instruments that are used in hedging transactions are effective at offsetting changes in either the fair value or cash flows of the related underlying exposure. All of our derivatives are commonly used over-the-counter instruments with liquid markets or are traded on the New York Mercantile Exchange. We do not enter into derivative financial instruments for trading or speculative purposes.

### **Commodity Price Risk Hedging**

We may use derivatives, principally futures and options, to hedge our exposure to market price volatility related to our inventory or future sales of crude oil. Derivatives used to hedge market price volatility related to inventory are generally designated as fair value hedges, and derivatives related to the future sales of crude oil are generally classified as cash flow hedges. The values of derivative instruments are included in Other assets or in Other current liabilities in the accompanying consolidated balance sheets.

Changes in the fair value of our derivative instruments related to crude oil inventory are recognized in net income. For the six months ended June 30, 2006 and 2005, crude oil sales, net of purchases were net of \$3.2 million and \$0.5 million in losses, respectively, reflecting changes in the fair value of derivative instruments held as hedges related to crude oil marketing activities. Losses on derivatives were generally offset by gains in physical crude oil inventory positions. Changes in the fair value of our derivative instruments related to the future sale of crude oil are deferred and reflected in accumulated other comprehensive income, a component of partners' capital in the balance sheet, until the related revenue is reflected in the consolidated statements of income. As of June 30, 2006, no amount relating to the change in the fair value of highly effective derivative instruments was included in accumulated other comprehensive income, as there were no such hedges.

### **Interest Rate Risk Hedging**

In connection with the issuance of our 7 $\frac{1}{8}$ % senior notes due 2014, we entered into interest rate swap agreements with an aggregate notional principal amount of \$80.0 million to receive interest at a fixed rate of 7 $\frac{1}{8}$ % and to pay interest at an average variable rate of six month LIBOR plus 1.6681% (set in advance or in arrears depending on the swap transaction). The interest rate swaps mature June 15, 2014 and are callable at the same dates and terms as the 7 $\frac{1}{8}$ % senior notes. We designated these swaps as a hedge of the change in the senior notes fair value attributable to changes in the six month LIBOR interest rate. Changes in fair values of the interest rate swaps are recorded into earnings each period. Similarly, changes in the fair value of the underlying \$80.0 million of senior notes, which are expected to be offsetting to changes in the fair value of the interest swaps, are recorded into earnings each period. At June 30, 2006, we recorded a decrease of \$2.5 million in the fair value of interest rate swaps. For the six months ended June 30, 2006, we recognized reductions in interest expense of \$0.1 million related to the difference between the fixed rate and the floating rate of interest on the interest rate swaps. For the six months ended June 30, 2006 and 2005, we had an immaterial amount of ineffectiveness relating to these interest rate swaps.

We are subject to risks resulting from interest rate fluctuations as the interest cost on our credit facilities and the \$80 million interest swap on the senior notes are based on variable rates. If our interest rates were to increase 1.0% for the remainder of 2006 as compared to the rate at December 31, 2005, our interest expense for the remainder of 2006 would increase \$2.2 million based on our outstanding debt balances at June 30, 2006.

### Currency Exchange Rate Risk Hedging

The purpose of our foreign currency hedging activities is to reduce the risk that our cash inflows resulting from interest payments from our Canadian subsidiaries on intercompany debt will be adversely affected by changes in the U.S./Canadian exchange rate.

We entered into forward exchange contracts to hedge receipt of forecasted interest payments denominated in Canadian dollars. The effective portion of the change in fair value of this contract, which has been designated as a cash flow hedge, is reported in accumulated other comprehensive income in the accompanying balance sheet and will be reclassified into earnings in Other income in the same period during which the hedged transaction affects earnings. The ineffective portion, if any, of the change in fair value of this instrument will be immediately recognized in earnings. These foreign exchange contracts as of June 30, 2006 are as follows:

	Canadian dollars (in thousands)	US dollars	Average Exchange Rate
2006	\$ 3,700	\$ 3,156	Cdn\$1.18 to U.S. \$1.00
2007	6,600	5,662	Cdn\$1.17 to U.S. \$1.00
2008	3,193	2,754	Cdn\$1.16 to U.S. \$1.00

### Credit Risks

By using derivative financial instruments to hedge exposures related to changes in commodity prices, interest rates and currency exchange rates, we expose ourselves 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 changes in commodity prices, interest rates or currency exchange rates. The market risk associated with price volatility is managed by established parameters that limit the types and degree of market risk that may be undertaken.

Credit risk is the risk of loss arising from the failure of the derivative agreement counterparty to perform under the terms of the derivative agreement. When the fair value of a derivative agreement is positive, the counterparty is liable to us, which creates credit risk for us. When the fair value of a derivative agreement is negative, we are liable to the counterparty and, therefore, it creates credit risk for the counterparty. The counterparties we transact with are large, well known companies in the industry or large creditworthy financial institutions. As such, we believe our exposure to counterparty credit risk is low. Nonetheless, there can be no assurance as to the performance of a counterparty.

## ITEM 4. Controls and Procedures

### Disclosure Controls and Procedures

We have established disclosure controls and procedures to ensure that material information relating to us, including our consolidated subsidiaries, is made known to the officers who certify our financial reports and to other members of our senior management and our Board of Directors. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management is required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

Based on their evaluation as of June 30, 2006, our principal executive officer and principal financial officer have concluded that, as of the end of the period covered by this report, our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the Exchange Act)) are effective to ensure that the information required to be disclosed by us in the reports

we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

***Internal Control Over Financial Reporting***

Our management, including the Chief Executive Officer and Chief Financial Officer, have evaluated our internal control over financial reporting as of June 30, 2006, and have concluded that there has not been any change during our most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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**PART II. OTHER INFORMATION**

**ITEM 1. Legal Proceedings**

See discussion of legal proceedings in Note 4 Contingencies in the accompanying condensed consolidated financial statements.

On or about March 17, 2006, one of the Partnership's subsidiaries, Pacific Pipeline System LLC ( PPS ), was served with a four count misdemeanor action, entitled *The People of the State of California v. Pacific Pipeline System, LLC*, Los Angeles Superior Court Case No. 6NW01020, which alleges the violation by PPS of two strict liability statutes under the California Fish and Game Code for the unlawful deposit of oil or substances harmful to wildlife into the environment, and violations of two sections of the California Water Code for the willful and intentional discharge of pollution into state waters. These alleged violations relate to the release of crude oil from PPS's Line 63 into Pyramid Lake (see Note 4 Contingencies in the accompanying condensed consolidated financial statements). The fines that can be assessed against PPS for the violations of the strict liability statutes are based, in large measure, on the volume of unrecovered crude oil that was released into the environment, and, therefore, the maximum fine that can be assessed is estimated to be approximately \$870,000, in the aggregate. This amount is subject to downwards adjustment as additional information becomes known with respect to actual volumes of recovered crude oil, and the State of California has the discretion to further reduce the fine after considering mitigating factors such as the fact that the release was not caused by any wrongful conduct of PPS. Because of the uncertainty associated with these factors, the final amount of the fine that will be assessed for the strict liability offenses cannot be ascertained.

The penalties that could be assessed for the alleged California Water Code violations are also not readily quantifiable, but we believe the penalties would not exceed \$50,000, in the aggregate. We believe, however, that the allegations of Water Code violations are without merit and intend to vigorously defend against them.

On June 15, 2006, a lawsuit was filed in the Superior court of California, County of Los Angeles, entitled *Kosseff v. Pacific Energy, et al.*, case no. BC 3544016. The plaintiff alleges that he is a unitholder of the Partnership and seeks to represent a class comprising all of the Partnership's unitholders. The complaint names as defendants the Partnership and certain of the officers and directors of the Partnership's general partner, and asserts claims of self-dealing and breach of fiduciary duty in connection with the pending merger with PAA and related transactions. Among other allegations, the plaintiff alleges that (1) the proposed transaction was the product of a flawed process that would result in the sale of the Partnership at an unfairly low price, (2) subsequent quarterly financial results for the Partnership would have had a material positive impact on the Partnership's common unit price had the proposed transaction not been announced, and thus the premium being offered to the Partnership's unitholders was manufactured by the defendants based on the timing of the announcement of the proposed transaction, (3) because of various conflicts of interest, the defendants have acted to better their own interests at the expense of the Partnership's public unitholders, (4) the defendants favored the proposed transaction in order to secure accelerated vesting of equity compensation under change in control provisions in contracts they have with the Partnership, and (5) the defendants were assured that Lehman Brothers Inc. would rubber-stamp the transaction as fair and, for that reason Lehman [Brothers Inc.] was hand-picked by the defendants to issue the so-called fairness opinion. The plaintiff seeks injunctive relief against completing the merger or, if the merger is completed, rescission of the merger, other equitable relief, and recovery of the plaintiff's costs and attorneys' fees. The Partnership believes that the lawsuit is without merit and intends to defend against it vigorously. There can be no assurance that additional claims may not be made or filed, the substance of which may be similar to the allegations described above or that otherwise might arise from, or in connection with, the merger agreement and the transaction it contemplates.

**ITEM 1A. Risk Factors**

The risk factors included in our annual report on Form 10-K for the year ended December 31, 2005 have not materially changed with the exception of the addition of risk factors related to the proposed merger with PAA. Some of the risks which may be relevant to us include:

***Business Uncertainties and Contractual Restrictions While Merger is Pending*** ***Uncertainty*** about the effect of the merger on employees, suppliers, partners, regulators and customers may have an adverse effect on us. These uncertainties may impair our ability to attract, retain and motivate key personnel until the merger is consummated, and could cause suppliers, customers and others that deal with us to defer purchases or other decisions concerning us, or seek to change existing business relationships with us. Employee retention may be particularly challenging while the merger is pending, as employees may experience uncertainty about their future roles with PAA. In addition, the merger agreement restricts us from making certain acquisitions and taking other specified actions without PAA's approval. These restrictions could prevent us from pursuing attractive business opportunities that may arise prior to the completion of the merger.

***Failure to Complete Merger Could Negatively Impact Stock Price, Future Business and Financial Results*** ***Although*** we have agreed that our board of directors will, subject to fiduciary exceptions, recommend that its stockholders approve and adopt the merger agreement, there is no assurance that the merger agreement and the merger will be approved, and there is no assurance that the other conditions to the completion of the merger will be satisfied. If the merger is not completed, we will be subject to several risks, including the following:

- we may be required to pay PAA a termination fee of \$40 million in the aggregate if the merger agreement is terminated under certain circumstances and we enter into or complete an alternative transaction;
- the current market price of our common units may reflect a market assumption that the merger will occur, and a failure to complete the merger could result in a negative perception by the stock market of us generally and a resulting decline in the market price of our common units;
- certain costs relating to the merger (such as legal, accounting and financial advisory fees) are payable by us whether or not the merger is completed;
- there may be substantial disruption to our business and a distraction of its management and employees from day-to-day operations, because matters related to the merger (including integration planning) may require substantial commitments of time and resources, which could otherwise have been devoted to other opportunities that could have been beneficial to us;
- our business could be adversely affected if we are unable to retain key employees or attract qualified replacements; and
- we would continue to face the risks that we currently face as an independent company.

There are substantial risks and uncertainties relating to the pending merger between the Partnership and PAA and the combined company following the merger. PAA filed a joint proxy statement/prospectus on Form S-4 on July 11, 2006 relating to the merger which includes a discussion of these risks. Upon being declared effective by the Securities and Exchange Commission, a definitive joint proxy statement/prospectus will be sent to security holders of the Partnership and PAA seeking their approval of the merger and related transactions. Investors and security holders are urged to carefully read the joint proxy statement/prospectus because it contains important information, including detailed risk factors, regarding the Partnership, PAA and the merger. Investors and security holders may obtain a free copy of the definitive joint proxy statement/prospectus, when it becomes available, and other documents containing information about the Partnership and PAA, without charge, at the SEC's web site at



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www.sec.gov. Copies of the definitive joint proxy statement/prospectus, when it becomes available, and the SEC filings that are incorporated by reference in the joint proxy statement/prospectus may also be obtained free of charge by directing a request to the Partnership or PAA. The Partnership urges unit holders and potential purchasers of its common units to review these materials.

**ITEM 6. Exhibits**

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

Exhibit Number	Description
Exhibit 2.1	Agreement and Plan of Merger dated as of June 12, 2006 by and among Plains All American Pipeline, L.P., Plains AAP, L.P., Plains All American GP LLC, Pacific Energy Partners, L.P., Pacific Energy Management LLC and Pacific Energy GP, LP. (incorporated by reference to Exhibit 2.1 to the Partnership's current report on Form 8-K filed June 13, 2006)
Exhibit 2.2	First Amendment to Agreement and Plan of Merger, dated July 19, 2006, by and among Pacific Energy Partners, L.P., Plains All American Pipeline, L.P., Pacific Energy GP, LP, Pacific Energy Management LLC, Plains AAP, L.P. and Plains All American GP LLC. (incorporated by reference to Exhibit 2.1 to the Partnership's current report on Form 8-K filed July 20, 2006)
Exhibit 2.3	Purchase Agreement dated as of June 12, 2006 by and between Plains All American Pipeline, L.P. and LB Pacific, LP. (incorporated by reference to Exhibit 2.2 to the Partnership's current report on Form 8-K filed June 13, 2006)
Exhibit 10.1	Executive compensation package approved on May 2, 2006 (incorporated by reference to Exhibit 10.1 to the Partnership's current report on Form 8-K filed May 8, 2006)
* Exhibit 10.2	Amended annual incentive compensation plan and severance plan
* Exhibit 31.1	Certification of Principal Executive Officer of Pacific Energy Management LLC, General Partner of Pacific Energy GP, LP, 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 Management LLC, General Partner of Pacific Energy GP, LP, 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 Management LLC, General Partner of Pacific Energy GP, LP, 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 Management LLC, General Partner of Pacific Energy GP, LP, 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.

**SIGNATURES**

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant 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, LP,  
its general partner**

**By: PACIFIC ENERGY MANAGEMENT LLC,  
its general partner**

By: /s/ IRVIN TOOLE, JR.

Irvin Toole, Jr.

*President, Chief Executive Officer and Director*

*(Principal Executive Officer)*

*August 7, 2006*

By: /s/ GERALD A. TYWONIUK

Gerald A. Tywoniuk

*Senior Vice President and Chief Financial Officer*

*(Principal Financial Officer)*

*August 7, 2006*

## EXHIBIT INDEX

Exhibit Number		Description
Exhibit 2.1		Agreement and Plan of Merger dated as of June 12, 2006 by and among Plains All American Pipeline, L.P., Plains AAP, L.P., Plains All American GP LLC, Pacific Energy Partners, L.P., Pacific Energy Management LLC and Pacific Energy GP, LP. (incorporated by reference to Exhibit 2.1 to the Partnership's current report on Form 8-K filed June 13, 2006)
Exhibit 2.2		First Amendment to Agreement and Plan of Merger, dated July 19, 2006, by and among Pacific Energy Partners, L.P., Plains All American Pipeline, L.P., Pacific Energy GP, LP, Pacific Energy Management LLC, Plains AAP, L.P. and Plains All American GP LLC. (incorporated by reference to Exhibit 2.1 to the Partnership's current report on Form 8-K filed July 20, 2006)
Exhibit 2.3		Purchase Agreement dated as of June 12, 2006 by and between Plains All American Pipeline, L.P. and LB Pacific, LP. (incorporated by reference to Exhibit 2.2 to the Partnership's current report on Form 8-K filed June 13, 2006)
Exhibit 10.1		Executive compensation package approved on May 2, 2006 (incorporated by reference to Exhibit 10.1 to the Partnership's current report on Form 8-K filed May 8, 2006)
* Exhibit 10.2		Amended annual incentive compensation plan and severance plan
* Exhibit 31.1		Certification of Principal Executive Officer of Pacific Energy Management LLC, General Partner of Pacific Energy GP, LP, 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 Management LLC, General Partner of Pacific Energy GP, LP, 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 Management LLC, General Partner of Pacific Energy GP, LP, 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 Management LLC, General Partner of Pacific Energy GP, LP, 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.