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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, DC 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of The Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) July 14, 2006

Plains All American Pipeline, L.P.

(Exact name of registrant as specified in its charter)

DELAWARE	**1-14569**	**76-0582150**
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

333 Clay Street, Suite 1600 Houston, Texas 77002
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code **(713) 646-4100**

N/A
(Former name or former address, if changed since last report.)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 9.01 ***Financial Statements and Exhibits***

On June 12, 2006 Plains All American Pipeline, L.P. (the "Partnership") announced that it had entered into a Purchase Agreement and an Agreement and Plan of Merger, pursuant to which Pacific Energy Partners, L.P. ("PPX") will be merged into the Partnership. The attached exhibits include the historical financial statements of PPX and pro forma financial statements for the probable acquisition.

(d) *Exhibits*

23.1	Consent of KPMG LLP
99.1	Pacific Energy Partners, L.P. Condensed Consolidated Financial Statements (Unaudited) as of March 31, 2006 and for the three months ended March 31, 2006 and March 31, 2005.
99.2	Pacific Energy Partners, L.P. Consolidated Financial Statements as of December 31, 2005 and for the three years ended December 31, 2005.
99.3	Unaudited Pro Forma Condensed Combined Financial Statements of Plains All American Pipeline, L.P. as of and for the three months ended March 31, 2006 and for the year ended December 31, 2005.

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 hereunto duly authorized.

	PLAINS ALL AMERICAN PIPELINE, L.P.
Date: July 14, 2006	By: Plains AAP, L.P., its general partner
	By: Plains All American GP LLC, its general partner
	By: /s/ TINA L. VAL
	Name: Tina L. Val Title: Vice President—Accounting and Chief Accounting Officer

INDEX TO EXHIBITS

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Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

The Board of Directors of Pacific Energy Management LLC of Pacific Energy Partners, L.P.:

We consent to the incorporation by reference in the registration statements on Form S-3 (No. 333-126447), Form S-4 (No. 333-135712) and on Form S-8 (Nos. 333-91141, 333-54118, 333-74920 and 333-122806) of Plains All American Pipeline, L.P. of our report dated March 10, 2006, with respect to the consolidated balance sheets of Pacific Energy Partners, L.P. and subsidiaries as of December 31, 2005 and 2004, and the related consolidated statements of income, partners' capital, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2005, which report appears in the current report on Form 8-K of Plains All American Pipeline, L.P. dated July 14, 2006.

/s/ KPMG LLP

Los Angeles, California
July 14, 2006

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Consent of Independent Registered Public Accounting Firm

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Exhibit 99.1

Pacific Energy Partners, L.P.

Pacific Energy Partners, L.P. Condensed Consolidated Financial Statements (Unaudited) as of March 31, 2006 and for the three months ended March 31, 2006 and March 31, 2005.

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PACIFIC ENERGY PARTNERS, L.P.

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	March 31, 2006	December 31, 2005
	(in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 11,944	$ 18,064
Crude oil sales receivable	108,331	95,952
Transportation and storage accounts receivable	25,910	30,100
Canadian goods and services tax receivable	6,478	8,738
Insurance proceeds receivable	7,440	9,052
Due from related parties	229	—
Crude oil and refined products inventory	36,391	20,192
Prepaid expenses	5,672	7,489
Other	3,791	2,528
Total current assets	206,186	192,115
Property and equipment, net	1,205,642	1,185,534
Intangible assets, net	68,426	69,180
Investment in Frontier	8,089	8,156
Other assets, net	17,907	21,467
	$ 1,506,250	$ 1,476,452
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 33,425	$ 43,859
Accrued crude oil purchases	113,182	96,651
Line 63 oil release reserve	2,787	4,448
Accrued interest	6,553	4,929
Other	5,050	6,300
Total current liabilities	160,997	156,187
Senior notes and credit facilities, net	600,985	565,632
Deferred income taxes	35,631	35,771
Environmental liabilities	16,671	16,617
Other liabilities	3,762	4,006
Total liabilities	818,046	778,213
Commitments and contingencies (note 4)		
Partners' capital:		
Common unitholders (31,457,782 and 31,448,931 units outstanding at March 31, 2006 and December 31, 2005, respectively)	636,710	644,589
Subordinated unitholders (7,848,750 units outstanding at March 31, 2006 and December 31, 2005)	22,725	24,758
General Partner interest	12,326	12,535
Undistributed employee long-term incentive compensation	41	—
Accumulated other comprehensive income	16,402	16,357
Net partners' capital	688,204	698,239
	$ 1,506,250	$ 1,476,452

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(Unaudited)

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
	(in thousands, except per unit amounts)	
Revenues:		
Pipeline transportation revenue	$ 33,857	$ 28,037
Storage and terminaling revenue	20,086	10,322
Pipeline buy/sell transportation revenue	9,699	9,106
Crude oil sales, net of purchases of $256,319 and $114,391 for the three months ended March 31, 2006 and 2005	6,809	1,782
	70,451	49,247
Costs and Expenses:		
Operating (which excludes $586 of compensation expense for 2005 reported in accelerated long-term incentive plan compensation expense)	33,419	21,754
General and administrative (which excludes $2,529 of compensation expense for 2005 reported in accelerated long-term incentive plan compensation expense)	6,873	5,172
Accelerated long-term incentive plan compensation expense	—	3,115
Line 63 oil release costs	—	2,000
Transaction costs	—	1,807
Depreciation and amortization	10,002	6,529
	50,294	40,377
Share of net income of Frontier	398	357
Operating income	20,555	9,227
Interest expense	(9,088)	(5,598)
Interest and other income	443	353
Income before income taxes	11,910	3,982
Income tax (expense) benefit:		
Current	(394)	(732)
Deferred	98	171
	(296)	(561)
Net income	$ 11,614	$ 3,421
Net income (loss) for the general partner interest	$ (19)	$ (1,702)
Net income for the limited partner interests	$ 11,633	$ 5,123
Basic and diluted net income per limited partner unit	$ 0.30	$ 0.17
Weighted average limited partner units outstanding:		
Basic	39,301	29,655
Diluted	39,313	29,720

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P.

CONDENSED CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL

(Unaudited)

	Limited Partner Units		Limited Partner Amounts					
	Common	Subordinated	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	—	—	9,310	2,323	(19)	—	—	11,614
Distribution to partners	—	—	(17,454)	(4,356)	(706)	—	—	(22,516)
Employee compensation under LB Pacific, LP option plan	—	—	—	—	511	—	—	511
Employee compensation under long-term incentive plan	—	—	—	—	—	356	—	356
Issuance of common units pursuant to long-term incentive plan	9	—	265	—	5	(315)	—	(45)
Foreign currency translation adjustment	—	—	—	—	—	—	(269)	(269)
Change in fair value of crude oil and foreign currency hedging contracts	—	—	—	—	—	—	314	314
Balance, March 31, 2006	31,458	7,849	$ 636,710	$ 22,725	$ 12,326	$ 41	$ 16,402	$ 688,204

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited)

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
	(in thousands)	
Net income	$ 11,614	$ 3,421
Change in fair value of crude oil hedging derivatives	260	(1,132)
Change in fair value of foreign currency hedging derivatives	54	—
Change in foreign currency translation adjustment	(269)	(537)
Comprehensive income	$ 11,659	$ 1,752

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
	(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 11,614	$ 3,421
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	10,002	6,529
Amortization of debt issue costs	606	459
Non-cash portion of employee compensation under long-term incentive plan	356	2,886
Non-cash employee compensation under the LB Pacific, LP option plan	511	—
Deferred tax expense (benefit)	(98)	(171)
Share of net income of Frontier	(398)	(357)
Distributions from Frontier, net	422	—
Net changes in operating assets and liabilities:		
Crude oil sales receivable	(12,305)	(23,327)
Transportation and storage accounts receivable	4,195	(1,832)
Insurance proceeds receivable	1,612	(11,496)
Crude oil and refined products inventory	(16,241)	(17,246)
Other current assets and liabilities	1,562	(1,754)
Accounts payable and other accrued liabilities	(7,754)	7,375
Accrued crude oil purchases	16,489	38,176
Line 63 oil release reserve	(1,661)	13,496
Other non-current assets and liabilities	(2,897)	(301)
NET CASH PROVIDED BY OPERATING ACTIVITIES	6,015	15,858
CASH FLOWS FROM INVESTING ACTIVITIES		
Acquisitions	(2,361)	—
Additions to property and equipment	(24,158)	(4,389)
Other	110	129
NET CASH USED IN INVESTING ACTIVITIES	(26,409)	(4,260)
CASH FLOWS FROM FINANCING ACTIVITIES		
Capital contributions from the general partner	—	2,438
Proceeds from credit facilities	74,417	26,833
Repayment of credit facilities	(37,366)	(25,854)
Deferred financing costs	—	(600)
Distributions to partners	(22,516)	(15,114)
Related parties	(229)	(661)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	14,306	(12,958)
Effect of exchange rates on cash	(32)	74
NET DECREASE IN CASH AND CASH EQUIVALENTS	(6,120)	(1,286)
CASH AND CASH EQUIVALENTS, beginning of reporting period	18,064	23,383
CASH AND CASH EQUIVALENTS, end of reporting period	$ 11,944	$ 22,097

See accompanying notes to condensed consolidated financial statements.

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.

The unaudited condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America for interim financial reporting and with Securities and Exchange Commission ("SEC") regulations. Accordingly, these statements have been condensed and do not include all of the information and footnotes required for complete financial statements. These statements involve the use of estimates and judgments where appropriate. In the opinion of management, all adjustments, consisting of normal recurring accruals considered necessary for a fair presentation, have been included. The results of operations for the three months ended March 31, 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 3 and 5 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.

2. NET INCOME PER LIMITED PARTNER UNIT

Basic net income per limited partner unit is determined by dividing net income, after adding back costs allocated to the General Partner and deducting the amounts allocated to the General Partner interest (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 and restricted units by application of the treasury stock method.

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.

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 March 31, 2006	Three Months Ended March 31, 2005
	(in thousands)	
Numerator:		
Net income allocated to limited partners:		
Net income	$ 11,614	$ 3,421
Costs allocated to the general partner(1):		
LB Pacific, LP Option Plan cost	511	—
Senior Notes consent solicitation and other costs	—	893
Severance and other costs	—	914
Total costs allocated to the general partner	511	1,807
Income before costs allocated to the general partner	12,125	5,228
Less: general partner incentive distributions	(255)	—
	11,870	5,228
General partner 2% ownership	(237)	(105)
Net income for the limited partners	$ 11,633	$ 5,123
Denominator:		
Basic weighted average limited partner units	39,301	29,655
Effect of restricted units	12	47
Effect of options	—	18
Diluted weighted average limited partner units	39,313	29,720
Basic and diluted net income per limited partner unit	$ 0.30	$ 0.17

(1) See "Note 3—Related Party Transactions" for a description of costs reimbursed by the General Partner.

3. RELATED PARTY TRANSACTIONS

The Partnership's General Partner does not receive any management fee or other compensation in connection with its management of the Partnership's business, but is entitled to reimbursement for all direct and indirect expenses incurred on the Partnership's behalf.

Cost Reimbursements

Payroll expenses: 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 its executives and key employees under the Plan, although generally accepted accounting principles require that the Partnership record an expense in its financial statements for the plan benefits to employees providing services to the Partnership, with a corresponding increase in the general partner's capital account.

The option plan is administered by the board of directors of LB Pacific GP, LLC. 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 general partner of LBP. 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. In general, options granted will become exercisable over a period determined by the board of directors of LB Pacific GP, LLC. In addition, the board of directors of LB Pacific GP, LLC may determine whether any unit options may become exercisable upon a change in control of LB Pacific GP, LLC, LB Pacific, LP, or our General Partner.

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 appropriate level of long term compensation paid by the Partnership.

In January 2006, LBP granted options representing a maximum 24% interest in LBP, which options vest in 10 years (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 months ended March 31, 2006, the Partnership recognized $0.5 million in compensation expense relating to the LBP options and recorded a capital contribution from the General Partner for the same amount. At March 31, 2006, there was $8.1 million of total unrecognized compensation cost related to nonvested options granted under the plan; that cost is expected to be recognized over the remaining period of 9.75 years. At March 31, 2006, all granted LBP options remained outstanding.

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 $1.2 million incurred for the consent solicitation, $0.6 million was capitalized as deferred financing costs and $0.6 million was expensed.

Other Related Party Transactions

Revenue from Related Parties: One of the Partnership's subsidiaries, Rocky Mountain Pipeline System LLC ("RMPS") serves as the contract operator for certain gas producing properties owned by a subsidiary of Anschutz in Wyoming and Utah, in exchange for which RMPS is reimbursed its direct costs of operation and is paid an annual fee of $0.3 million as compensation for the time spent by RMPS management and for other overhead services related to their activities.

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 month periods ended March 31, 2006 and 2005. The Partnership owns a 22.22% partnership interest in Frontier.

Expenses Paid to Related Parties: Until December 31, 2005, the Partnership utilized the financial accounting system owned and provided by Anschutz under a shared services arrangement for a fee of $0.1 million per year and Anschutz charged the Partnership for any out-of-pocket costs it incurred. The fixed annual fee included all license, maintenance and employee costs associated with the Partnership's use of the financial accounting system.

In January 2003, the Partnership began leasing approximately 4,700 square feet of office space from an affiliate of Anschutz, for a term of five years at an annual cost of $0.1 million per year. The lease was terminated in February 2006.

4. 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 $25.7 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 March 31, 2006, the Partnership had incurred approximately $21.4 million of the total expected remediation costs related to the oil release for work performed through that date. The Partnership estimates that $2.8 million of the remaining remediation costs will be incurred for the remainder of 2006 and $0.7 million (included in "Other liabilities" in the accompanying balance sheet) will be incurred in 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 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 March 31, 2006, the Partnership has recovered $15.6 million from insurance and recorded receivables of $8.1 million for future insurance recoveries it deems probable, of which $0.7 million is considered long-term and is included in "Other assets, net" in the accompanying consolidated balance sheet.

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 from $0 to $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." Based on management's 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.

Litigation

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 March 31, 2006) in general damages, Cdn$2 million (approximately U.S.$1.7 million at March 31, 2006) in special damages, and, in addition, unspecified amounts for punitive, exemplary and aggravated damages, costs and interest. The Statement of Claim has not been served on RPC, so RPC has not been required to file an answer. 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.

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.

5. RESTRICTED UNITS

A restricted unit is a "phantom" unit. 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, the General Partner awarded 46,815 restricted units to key employees that vest over a three-year period, beginning on March 1, 2006, and that are also subject to meeting annual financial performance objectives and to outside directors that vest over a three-year period beginning March 1, 2006. The financial measure used is the Partnership's distributable cash flow per unit, as determined by the Compensation Committee, for the calendar year preceding each of the three annual vesting dates. The number of units to be delivered in any year, if any, will be based on accomplishment of performance targets 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 three months ended March 31, 2006 is as follow:

	Number of Units	Weighted Average Grant Date Fair Value
		(in thousands)
Outstanding at January 1, 2006	—	$ —
Changes during the year:		
Granted	46,815	1,410
Vested	(10,439)	(314)
Forfeited	(5,166)	(156)
Outstanding at March 31, 2006	31,210	$ 940

Compensation expense recognized for granted performance 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 months ended March 31, 2006, the Partnership incurred $0.4 million 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.

6. 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), 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), a marketer of crude oil.

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)		
Three months ended March 31, 2006				
Revenues:				
Pipeline transportation revenue	$ 17,163	$ 18,868	$ (2,174)	$ 33,857
Storage and terminaling revenue	20,086	—	—	20,086
Pipeline buy/sell transportation revenue(1)	—	9,699	—	9,699
Crude oil sales, net of purchases(2)	7,311	(360)	(142)	6,809
Net revenue	44,560	28,207		70,451
Expenses:				
Operating	21,432	14,303	(2,316)	33,419
Depreciation and amortization	5,499	4,503		10,002
Total expenses	26,931	18,806		43,421
Share of net income of Frontier	—	398		398
Operating income from segments(3)	$ 17,629	$ 9,799		$ 27,428
Business unit assets(4)	$ 884,143	$ 571,391		$ 1,455,534
Capital expenditures(5)	$ 11,610	$ 5,816		$ 17,426
Three months ended March 31, 2005				
Revenues:				
Pipeline transportation revenue	$ 17,443	$ 12,456	$ (1,862)	$ 28,037
Storage and terminaling revenue	10,472	—	(150)	10,322
Pipeline buy/sell transportation revenue(1)	—	9,106		9,106
Crude oil sales, net of purchases(2)	1,812	—	(30)	1,782
Net revenue	29,727	21,562		49,247
Expenses:				
Operating	14,507	9,289	(2,042)	21,754
Line 63 oil release costs(6)	2,000	—		2,000
Depreciation and amortization	3,477	3,052		6,529
Total expenses	19,984	12,341		30,283
Share of net income of Frontier	—	357		357
Operating income from segments(3)	$ 9,743	$ 9,578		$ 19,321
Business unit assets(4)	$ 538,568	$ 350,600		$ 889,168
Capital expenditures(5)	$ 750	$ 2,932		$ 3,682

(1) Pipeline buy/sell transportation revenue reflects net revenues of approximately $2.5 million on buy/sell transactions with different parties of $48.3 million. The remaining amount reflects net revenues on buy/sell transactions with the same party.

(2) The above amounts are net of purchases of $256.3 million and $114.3 million for 2006 and 2005, respectively.

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

	Three Months Ended March 31, 2006	2005
	(in thousands)	
Income Statement Reconciliation		
Operating income from above:		
West Coast Business Unit	$ 17,629	$ 9,743
Rocky Mountain Business Unit	9,799	9,578
Operating income before general and administrative expense	27,428	19,321
Less: General and administrative expense	(6,873)	(5,172)
Less: Accelerated long-term incentive plan compensation expense	—	(3,115)
Less: Transaction costs	—	(1,807)
Operating income	20,555	9,227
Interest expense	(9,088)	(5,598)
Other income	443	353
Income tax expense	(296)	(561)
Net income	$ 11,614	$ 3,421

(4) Business unit assets do not include assets related to the Partnership's parent level activity. As of March 31, 2006 and 2005, parent level related assets were $50.7 million and $30.9 million respectively.

(5) Segment capital expenditures do not include parent level capital expenditures. Parent level capital expenditures were $6.7 million and $0.7 million for the three months ended March 31, 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 $25.7 million of accrued costs relating to the release, net of insurance recoveries of $15.6 million to March 31, 2006 and accrued insurance receipts of $8.1 million.

7. SUBSEQUENT EVENT

On April 21, 2006, the Partnership declared a cash distribution of $0.5675 per limited partner unit, payable on May 12, 2006, to unitholders of record as of May 1, 2006.

8. 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 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:

Balance Sheet
March 31, 2006

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
			(in thousands)		
Assets:					
Current assets	$ 104,875	$ 157,298	$ 66,849	$ (122,836)	$ 206,186
Property and equipment	—	597,088	608,554	—	1,205,642
Equity investments	449,804	212,513	—	(654,228)	8,089
Intercompany notes receivable	662,763	340,838	—	(1,003,601)	—
Intangible assets	—	30,819	37,607	—	68,426
Other assets	11,304	(244)	6,847	—	17,907
Total assets	$ 1,228,746	$ 1,338,312	$ 719,857	$ (1,780,665)	$ 1,506,250
Liabilities and partners' capital:					
Current liabilities	$ 5,273	$ 215,309	$ 63,251	$ (122,836)	$ 160,997
Long-term debt	535,269	—	65,716	—	600,985
Deferred income taxes	—	597	35,034	—	35,631
Intercompany notes payable	—	662,763	340,838	(1,003,601)	—
Other liabilities	—	9,839	10,594	—	20,433
Total partners' capital	688,204	449,804	204,424	(654,228)	688,204
Total liabilities and partners' capital	$ 1,228,746	$ 1,338,312	$ 719,857	$ (1,780,665)	$ 1,506,250

Balance Sheet
December 31, 2005

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
			(in thousands)		
Assets:					
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
Total assets	$ 1,209,530	$ 1,292,151	$ 730,051	$ (1,755,280)	$ 1,476,452
Liabilities and partners' capital:					
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
Total partners' capital	698,239	429,802	189,083	(618,885)	698,239
Total liabilities and partners' capital	$ 1,209,530	$ 1,292,151	$ 730,051	$ (1,755,280)	$ 1,476,452

	Statement of Income Three Months Ended March 31, 2006				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands)				
Net operating revenues	$ —	$ 35,219	$ 37,547	$ (2,315)	$ 70,451
Operating expenses	—	(19,088)	(16,646)	2,315	(33,419)
General and administrative expense(1)	—	(6,210)	(663)	—	(6,873)
Accelerated long-term incentive plan compensation expense	—	—	—	—	—
Line 63 oil release costs	—	—	—	—	—
Transaction costs	—	—	—	—	—
Depreciation and amortization expense	—	(4,928)	(5,074)	—	(10,002)
Share of net income of Frontier	—	398	—	—	398
Operating income	—	5,391	15,164	—	20,555
Interest expense	(8,108)	(81)	(899)	—	(9,088)
Intercompany interest income (expense)	—	7,169	(7,169)	—	—
Equity earnings	19,942	7,404	—	(27,346)	—
Other income	(220)	337	326	—	443
Income tax benefit (expense)	—	(278)	(18)	—	(296)
Net income	$ 11,614	$ 19,942	$ 7,404	$ (27,346)	$ 11,614

	Statement of Income Three Months Ended March 31, 2005				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands)				
Net operating revenues	$ —	$ 14,268	$ 37,021	$ (2,042)	$ 49,247
Operating expenses	—	(9,968)	(13,828)	2,042	(21,754)
General and administrative expense(1)	—	(4,618)	(554)	—	(5,172)
Accelerated long-term incentive plan compensation expense	—	(2,684)	(431)	—	(3,115)
Line 63 oil release costs	—	—	(2,000)	—	(2,000)
Transaction costs	(893)	(914)	—	—	(1,807)
Depreciation and amortization expense	—	(1,624)	(4,905)	—	(6,529)
Share of net income of Frontier	—	357	—	—	357
Operating income	(893)	(5,183)	15,303	—	9,227
Interest expense	(4,078)	(679)	(841)	—	(5,598)
Intercompany interest income (expense)	—	6,271	(6,271)	—	—
Equity earnings	8,384	7,990	—	(16,374)	—
Other income	8	166	179	—	353
Income tax benefit (expense)	—	(181)	(380)	—	(561)
Net income	$ 3,421	$ 8,384	$ 7,990	$ (16,374)	$ 3,421

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

Statement of Cash Flows
Three Months Ended March 31, 2006

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
			(in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net income	$ 11,614	$ 19,942	$ 7,404	$ (27,346)	$ 11,614
Adjustments to reconcile net income to net cash provided by operating activities:					
Equity earnings	(19,942)	(7,404)	—	27,346	—
Distributions from subsidiaries	22,516	11,732	—	(34,248)	—
Depreciation, amortization and other	1,024	5,330	5,047	—	11,401
Net changes in operating assets and liabilities	(188)	(7,838)	(7,126)	(1,848)	(17,000)
NET CASH PROVIDED BY OPERATING ACTIVITIES	15,024	21,762	5,325	(36,096)	6,015
CASH FLOWS FROM INVESTING ACTIVITIES					
Acquisitions	—	(2,361)	—	—	(2,361)
Additions to property, equipment and other	(72)	(15,889)	(8,087)	—	(24,048)
Intercompany	(31,000)	—	—	31,000	—
NET CASH USED IN INVESTING ACTIVITIES	(31,072)	(18,250)	(8,087)	31,000	(26,409)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	17,006	(13,620)	5,824	5,096	14,306
Effect of translation adjustment	—	—	(32)	—	(32)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	958	(10,108)	3,030	—	(6,120)
CASH AND CASH EQUIVALENTS, beginning of reporting period	4,192	12,484	1,388	—	18,064
CASH AND CASH EQUIVALENTS, end of reporting period	$ 5,150	$ 2,376	$ 4,418	$ —	$ 11,944

	Statement of Cash Flows Three Months Ended March 31, 2005				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
			(in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net income	$ 3,421	$ 8,384	$ 7,990	$ (16,374)	$ 3,421
Adjustments to reconcile net income to net cash provided by operating activities:					
Equity earnings	(8,384)	(7,990)	—	16,374	—
Distributions from subsidiaries	15,114	12,673	—	(27,787)	—
Depreciation, amortization and other	157	4,325	4,864	—	9,346
Net changes in operating assets and liabilities	3,915	1,840	74	(2,738)	3,091
NET CASH PROVIDED BY OPERATING ACTIVITIES	14,223	19,232	12,928	(30,525)	15,858
CASH FLOWS FROM INVESTING ACTIVITIES					
Additions to property, equipment and other	—	(1,091)	(3,169)	—	(4,260)
Intercompany	(914)	—	—	914	—
NET CASH USED IN INVESTING ACTIVITIES	(914)	(1,091)	(3,169)	914	(4,260)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	(14,894)	(18,276)	(7,984)	28,196	(12,958)
Effect of translation adjustment	—	—	74	—	74
NET DECREASE IN CASH AND CASH EQUIVALENTS	(1,585)	(1,476)	1,775	—	(1,286)
CASH AND CASH EQUIVALENTS, beginning of reporting period	2,713	17,523	3,147	—	23,383
CASH AND CASH EQUIVALENTS, end of reporting period	$ 1,128	$ 16,047	$ 4,922	$ —	$ 22,097

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Exhibit 99.2

Pacific Energy Partners, L.P.

Pacific Energy Partners, L.P. Consolidated Financial Statements as of December 31, 2005 and for the three years ended December 31, 2005.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors of Pacific Energy Management LLC and
Unitholders of Pacific Energy Partners, L.P.:

We have audited the accompanying consolidated balance sheets of Pacific Energy Partners, L.P. and subsidiaries, as of December 31, 2005 and 2004, and the related consolidated statements of income, partners' capital, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2005. These consolidated financial statements are the responsibility of Pacific Energy Partners, L.P.'s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Pacific Energy Partners, L.P. and subsidiaries as of December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Pacific Energy Partners, L.P. and subsidiaries' internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 10, 2006 expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

/s/ KPMG LLP

Los Angeles, California
March 10, 2006

PACIFIC ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

December 31, 2005 and 2004

	2005	2004
	(in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 18,064	$ 23,383
Crude oil sales receivable	95,952	28,609
Transportation and storage accounts receivable	30,100	20,137
Canadian goods and services tax receivable	8,738	7,632
Insurance proceeds receivable (note 4)	9,052	—
Crude oil and refined products inventories (note 2)	20,192	9,174
Prepaid expenses	7,489	4,159
Other	2,528	2,451
Total current assets	192,115	95,545
Property and equipment, net (note 5)	1,185,534	718,624
Intangible assets, net (note 6)	69,180	37,894
Investment in Frontier (note 7)	8,156	7,886
Other assets, net	21,467	9,956
	$ 1,476,452	$ 869,905
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 43,859	$ 15,272
Accrued crude oil purchases	96,651	27,231
Line 63 oil release reserve (note 4)	4,448	—
Accrued interest	4,929	1,124
Due to related parties (note 8)	—	533
Other	6,300	3,885
Total current liabilities	156,187	48,045
Senior notes and credit facilities, net (note 9)	565,632	357,163
Deferred income taxes (note 11)	35,771	34,556
Environmental liabilities (note 12)	16,617	7,269
Other liabilities	4,006	406
Total liabilities	778,213	447,439
Commitments and contingencies (notes 12, 13 and 14)		
Partners' capital (note 15):		
Common unitholders (31,448,931 and 19,158,747 units outstanding at December 31, 2005 and 2004, respectively)	644,589	361,427
Subordinated unitholders (7,848,750 and 10,465,000 units outstanding at December 31, 2005 and 2004, respectively)	24,758	41,521
General Partner interest	12,535	6,280
Undistributed employee long-term incentive compensation	—	116
Accumulated other comprehensive income	16,357	13,122
Net partners' capital	698,239	422,466
	$ 1,476,452	$ 869,905

See accompanying notes to consolidated financial statements.

PACIFIC ENERGY PARTNERS, L. P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

Years ended December 31, 2005, 2004 and 2003

	2005	2004	2003
	(in thousands, except per unit amounts)		
Revenues:			
Pipeline transportation revenue	$ 116,648	$ 108,395	$ 101,811
Storage and terminaling revenue	51,986	37,577	12,711
Pipeline buy/sell transportation revenue	35,671	18,640	—
Crude oil sales, net of purchases of $623,115, $402,283 and $358,454 in 2005, 2004 and 2003, respectively	19,997	16,787	21,293
	224,302	181,399	135,815
Cost and Expenses:			
Operating	104,397	85,286	61,046
General and administrative	18,472	15,400	13,705
Accelerated long-term incentive plan compensation expense (note 18)	3,115	—	—
Line 63 oil release costs (note 4)	2,000	—	—
Transaction costs (notes 8 and 17)	1,807	—	—
Depreciation and amortization	29,406	24,173	18,865
	159,197	124,859	93,616
Share of net income (loss) of Frontier (note 7):			
Income before rate case and litigation expense	1,757	1,328	1,459
Rate case and litigation expense	—	—	(1,621)
Share of net income (loss) of Frontier	1,757	1,328	(162)
Write-down of idle property (note 2)	(450)	(800)	—
Operating income	66,412	57,068	42,037
Interest and other income	1,119	1,032	479
Write-off of deferred financing costs and interest rate swap termination expense (note 10)	—	(2,901)	—
Interest expense	(26,720)	(19,209)	(17,487)
Income before income taxes	40,811	35,990	25,029
Income tax (expense) benefit (note 11):			
Current	(1,252)	(326)	—
Deferred	89	65	—
	(1,163)	(261)	—
Net income	$ 39,648	$ 35,729	$ 25,029
Net income (loss) for the general partner interest (note 17)	$ (978)	$ 715	$ 501
Net income for the limited partner interests	$ 40,626	$ 35,014	$ 24,528
Net income per limited partner unit:			
Basic	$ 1.25	$ 1.23	$ 1.10
Diluted	$ 1.25	$ 1.23	$ 1.09
Weighted average limited partner units outstanding:			
Basic	32,381	28,406	22,328
Diluted	32,414	28,488	22,540

See accompanying notes to consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
Years ended December 31, 2005, 2004 and 2003
(in thousands)

	Limited Partner Units		Limited Partner Amounts					
	Common	Subordinated	Common	Subordinated	General Partner Interest	Undistributed Employee Long-Term Incentive Compensation	Accumulated Other Comprehensive Income (Loss)	Total
Balance, December 31, 2002	10,465	10,465	$ 163,172	$ 57,069	$ 2,329	$ 72	$ (7,375)	$ 215,267
Net income	—	—	12,963	11,565	501	—	—	25,029
Distributions to partners	—	—	(21,650)	(19,624)	(841)	—	—	(42,115)
Issuance of common units, net of fees and offering expenses	5,612	—	131,716	—	1,955	—	—	133,671
Redemption of common units held by general partner	(1,727)	—	(40,780)	—	—	—	—	(40,780)
Undistributed employee compensation under long-term incentive plan	—	—	—	—	—	3,233	—	3,233
Issuance of common units pursuant to long-term incentive plan	92	—	1,531	—	31	(2,567)	—	(1,005)
Change in fair value of interest rate and crude oil hedging derivatives	—	—	—	—	—	—	1,767	1,767
Balance, December 31, 2003	14,442	10,465	$ 246,952	$ 49,010	$ 3,975	$ 738	$ (5,608)	$ 295,067
Net income	—	—	22,096	12,918	715	—	—	35,729
Distributions to partners	—	—	(34,981)	(20,407)	(1,130)	—	—	(56,518)
Issuance of common units, net of fees and offering expenses	4,625	—	125,881	—	2,690	—	—	128,571
Undistributed employee compensation under long-term incentive plan	—	—	—	—	—	2,076	—	2,076
Issuance of common units pursuant to long-term incentive plan	92	—	1,479	—	30	(2,698)	—	(1,189)
Changes in fair value of interest rate and crude oil hedging derivatives	—	—	—	—	—	—	5,422	5,422
Foreign currency translation adjustment	—	—	—	—	—	—	13,308	13,308
Balance, December 31, 2004	19,159	10,465	$ 361,427	$ 41,521	$ 6,280	$ 116	$ 13,122	$ 422,466
Net income	—	—	29,027	11,599	(978)	—	—	39,648
Distributions to partners	—	—	(45,458)	(19,981)	(1,336)	—	—	(66,775)
Issuance of common units, net of fees and offering expenses	9,533	—	288,960	—	6,116	—	—	295,076
General partner contribution	—	—	—	—	2,407	—	—	2,407
Employee compensation under long-term incentive plan	—	—	—	—	—	2,886	—	2,886
Issuance of common units pursuant to long-term incentive plan	99	—	1,545	—	31	(3,002)	—	(1,426)
Exercise of unit options pursuant to long-term incentive plan	42	—	707	—	15	—	—	722
Conversion of subordinated units to common units	2,616	(2,616)	8,381	(8,381)	—	—	—	—
Changes in fair value of crude oil and foreign currency hedging contracts	—	—	—	—	—	—	(269)	(269)
Foreign currency translation adjustment	—	—	—	—	—	—	3,504	3,504
Balance, December 31, 2005	31,449	7,849	$ 644,589	$ 24,758	$ 12,535	$ —	$ 16,357	$ 698,239

See accompanying notes to consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years ended December 31, 2005, 2004 and 2003

	2005	2004	2003
		(in thousands)	
Net income	$ 39,648	$ 35,729	$ 25,029
Change in fair value of interest rate hedging derivatives	—	5,436	1,939
Change in fair value of crude oil hedging derivatives	(74)	(14)	(172)
Change in fair value of foreign currency hedging derivatives	(195)	—	—
Change in foreign currency translation adjustment	3,504	13,308	—
Comprehensive income	$ 42,883	$ 54,459	$ 26,796

See accompanying notes to consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years ended December 31, 2005, 2004 and 2003

	2005	2004	2003
		(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 39,648	$ 35,729	$ 25,029
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	29,406	24,173	18,865
Amortization of debt issue costs	2,027	1,537	1,028
Write-off of deferred financing costs	—	2,321	—
Write-down of idle property	450	800	—
Non-cash employee compensation under long-term incentive plan	2,886	2,076	3,233
Deferred tax expense (benefit)	(89)	(65)	—
Share of net (income) loss of Frontier	(1,757)	(1,328)	162
Other non-cash items	220	—	—
Distribution from (contribution to) Frontier, net	1,317	(44)	1,755
Net changes in operating assets and liabilities:			
Crude oil sales receivable	(66,968)	5,157	(9,609)
Transportation and storage accounts receivable	(9,951)	(1,311)	(6,260)
Insurance proceeds receivable	(9,052)	—	—
Other current assets and liabilities	(14,901)	(9,337)	557
Accounts payable and other accrued liabilities	29,453	(565)	726
Accrued crude oil purchases	68,974	(4,370)	7,217
Line 63 oil release reserve	4,448	—	—
Other non-current assets and liabilities	(3)	2,453	20
NET CASH PROVIDED BY OPERATING ACTIVITIES	76,108	57,226	42,723
CASH FLOWS FROM INVESTING ACTIVITIES:			
Acquisitions	(462,553)	(138,701)	(169,740)
Additions to property and equipment	(51,717)	(16,520)	(10,892)
Other	1,519	(731)	300
NET CASH USED IN INVESTING ACTIVITIES	(512,751)	(155,952)	(180,332)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Issuance of common units, net of fees and offering expenses	288,960	125,881	131,716
Capital contributions from the general partner	8,569	2,720	1,986
Redemption of common units held by the general partner, net of underwriter's fees	—	—	(40,780)
Net proceeds from senior notes offerings	170,889	240,932	—
Repayment of term loan	—	(225,000)	—
Proceeds from credit facilities	283,502	140,922	166,000
Repayment of credit facilities	(249,466)	(115,253)	(93,000)
Deferred bank debt financing costs	(4,573)	(1,227)	—
Distributions to partners	(66,775)	(56,518)	(42,115)
Issuance of common units pursuant to exercise of unit options	707	—	—
Change in balance due from or to related parties	(533)	(47)	(372)
NET CASH PROVIDED BY FINANCING ACTIVITIES	431,280	112,410	123,435
Effect of exchange rates on cash	44	—	—
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(5,319)	13,684	(14,174)
CASH AND CASH EQUIVALENTS, beginning of year	23,383	9,699	23,873
CASH AND CASH EQUIVALENTS, end of year	$ 18,064	$ 23,383	$ 9,699
Supplemental disclosures:			
Cash paid for interest	$ 22,462	$ 19,881	$ 16,252
Taxes paid	$ 665	$ 125	$ —
Non-cash financing and investing activities:			
Additions to equipment	$ —	$ —	$ 204

See accompanying notes to consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND BASIS OF PRESENTATION

Organization

Pacific Energy Partners, L.P., a Delaware limited partnership, was formed in February 2002 and completed its initial public offering of common units representing limited partner units on July 26, 2002. 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 (the "General Partner"), which, prior to its conversion to a limited partnership on March 3, 2005, was Pacific Energy GP, Inc., a corporation owned 100% by a subsidiary of The Anschutz Corporation ("Anschutz"). On March 3, 2005, Anschutz sold all of its interest in Pacific Energy GP, Inc. to LB Pacific, LP ("LBP"), which was formed by the Lehman Brothers Merchant Banking Group ("LBMB") in connection with the purchase (see "Note 8—Related Party Transactions"). Pacific Energy GP, LP 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 the Partnership and its General Partner. The Partnership's General Partner does not receive any management fee or other compensation in connection with its management of the Partnership's business, but is entitled to reimbursement for all direct and indirect expenses incurred on the Partnership's behalf.

The Partnership holds a 100% ownership interest in Pacific Energy Group LLC ("PEG"), whose 100% owned subsidiaries consist of:

(i) Pacific Pipeline System LLC ("PPS"), owner of Line 2000 and the Line 63 system;

(ii) Pacific Terminals LLC ("PT"), owner of the Pacific Terminals storage and distribution system;

(iii) Pacific Atlantic Terminals LLC ("PAT"), which was formed for the purpose of acquiring the California and East Coast terminal assets the Partnership purchased on September 30, 2005 as part of the acquisition of assets from Valero, L.P. (see "Note 3—Acquisitions");

(iv) Pacific Marketing and Transportation LLC ("PMT"), owner of the PMT gathering system and marketer of crude oil;

(v) Rocky Mountain Pipeline System LLC ("RMPS"), owner of the Western Corridor and Salt Lake City Core systems, and which acquired the West Pipeline system (which is now known as the Rocky Mountain Products Pipeline) on September 30, 2005 as part of the acquisition of assets from Valero, L.P.; and

(vi) Ranch Pipeline LLC ("RPL"), owner of a 22.22% partnership interest in Frontier Pipeline Company ("Frontier"), a Wyoming general partnership.

The Partnership holds 100% interest in PEG Canada GP LLC ("PEG Canada GP"), the general partner of PEG Canada, L.P. ("PEG Canada"), the holding company of the Partnership's Canadian subsidiaries. The Partnership owns 100% of the limited and general partner interests in PEG Canada, whose 100% owned subsidiaries consist of:

(i) Rangeland Pipeline Company ("RPC"), which owns 100% of Aurora Pipeline Company Ltd. ("Aurora") and a partnership interest in Rangeland Pipeline Partnership ("Rangeland Partnership");

(ii) Rangeland Northern Pipeline Company ("RNPC"), which owns the remaining partnership interest in Rangeland Partnership; and

(iii) Rangeland Marketing Company ("RMC").

Rangeland Partnership owns all of the assets that make up the Rangeland pipeline system except the Aurora pipeline, which is owned by Aurora.

The Partnership also owns 100% of Pacific Energy Finance Corporation, which was organized for the purpose of co-issuing the Partnership's senior notes.

Business Segment Reporting

The business segments of the Partnership consist of two geographic regions, the West Coast and the Rocky Mountains. The West Coast Business Unit includes PPS, PT, PAT and PMT. The Rocky Mountain Business Unit includes RMPS, RPL and PEG Canada and its Canadian subsidiaries RPC, Aurora, RNPC, RMC and Rangeland Partnership. Information relating to these two segments is summarized in "Note 20—Segment Information".

Basis of Presentation

The accompanying financial statements and related notes present the Partnership's (including all of its wholly-owned subsidiaries) consolidated financial position as of December 31, 2005 and 2004, and the consolidated results of the Partnership's operations, cash flows, changes in partners' capital and comprehensive income for the years ended December 31, 2005, 2004 and 2003. All significant intercompany balances and transactions have been eliminated during the consolidation process. Certain reclassifications were made to prior periods to conform to the current period presentation. Investments in affiliates, over which the Partnership has significant influence, are accounted for by the equity method.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Management Estimates

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

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

Revenue Recognition

Revenue from pipeline transportation services is recognized upon delivery of the product to the customer. Other revenue associated with the operation of the Partnership's pipelines is recognized as the services are performed.

Storage and distribution revenue is recognized monthly based on the lease of storage tanks, the use of distribution system assets, and the delivery of related incidental services.

The Rangeland system is a proprietary system. Therefore, customers who wish to transport commodities on the Rangeland system must either: (i) sell commodities at the inlet to the pipeline without repurchasing commodities; or (ii) sell commodities at an inlet point and repurchase such product at agreed-upon delivery points for the price paid at the inlet to the pipeline plus an established location differential on a pre-arranged basis. Revenue from buy/sell transactions is recognized on a net basis. Revenue is recognized when the commodity is delivered to the customer.

PMT's crude oil sales are recognized as the crude oil is delivered to customers, and are reflected separately, net of crude oil purchases, on the accompanying consolidated statements of income.

Regulation

The California Public Utilities Commission ("CPUC") regulates PPS's common carrier crude oil pipeline operations. All shipments on the regulated pipelines are governed by tariffs authorized and approved by the CPUC. Tariffs on the Line 2000 pipeline are market-based, established based on market considerations, subject to contractual terms. Tariffs on the Line 63 pipeline are cost-of-service based, designed to allow PPS to recover its various costs to operate and maintain the pipeline as well as a charge for depreciation of the capital investment in the pipeline and an authorized rate of return.

The CPUC also regulates PT's storage and distribution operations. The CPUC has authorized PT to establish the terms, conditions and charges for its storage and distribution services through negotiated contracts with its customers.

The West and East Coast products terminals are not regulated utilities, nor is the PMT gathering system, which is a proprietary intrastate operation.

The Western Corridor and Salt Lake City Core systems are common carrier pipelines that transport oil under cost-based tariffs under the jurisdiction of the Federal Energy Regulatory Commission ("FERC") and the Wyoming Public Service Commission ("WPSC"). The Rocky Mountain Products Pipeline that was acquired as part of the Valero Acquisition is a common carrier system that transports products under market-based FERC tariffs, except for one FERC regulated cost-based segment, and under cost-based tariffs under the jurisdiction of the states of Wyoming and Colorado.

The Rangeland system operates as a proprietary system, and accordingly the Partnership takes title to the crude oil that is gathered and transported. The Rangeland system is subject to the jurisdiction of the Alberta Energy and Utilities Board ("EUB"). The Aurora pipeline is subject to the jurisdiction of the Canadian National Energy Board ("NEB"). The EUB and NEB will generally not review rates set by a crude oil pipeline operator unless it receives a complaint.

Concentration of Customers and Credit Risk

A substantial portion of the West Coast transportation and storage business in 2005, 2004 and 2003 was with four customers who individually accounted for more that 10% of West Coast transportation and storage revenue. Collectively, these four customers accounted for approximately 60%, 73% and 76% of total West Coast transportation and storage revenue in 2005, 2004 and 2003, respectively. Two of these customers, Chevron and Shell Trading Company, who collectively accounted for approximately 32%, 46% and 47% of 2005, 2004 and 2003 transportation and storage revenue, respectively, have executed ten-year ship or pay transportation agreements expiring in 2009 whereby they have committed to ship minimum volumes that represent approximately 61% of their actual 2005 volumes transported on the Partnership's West Coast pipelines.

A substantial portion of the Partnership's Rocky Mountain pipeline transportation and storage business in 2005, 2004 and 2003 was with two customers who individually accounted for more that 10% of Rocky Mountain transportation revenue. Collectively, these two customers accounted for approximately 36%, 40% and 50% of total Rocky Mountain transportation revenue in 2005, 2004 and 2003, respectively. In addition, for the Partnership's Canadian buy/sell transportation revenue, in 2005 three customers accounted for 50% of the Partnership's Canadian net sales revenue and in 2004 two customers accounted for approximately 60% of the Partnership's Canadian net sales revenue. In 2005, three suppliers accounted for 58% of the Partnership's Canadian net purchase contracts and in 2004 one supplier accounted for 66% of the Partnership's Canadian net purchase contracts. Each of these customers and suppliers individually accounted for more that 10% of the Partnership's Canadian buy/sell transportation revenue and net purchase contracts.

Although the above concentration could affect the Partnership's overall exposure to credit risk, management believes that the risk is minimal given that a majority of its business is conducted with large, high credit quality companies within the industry. The Partnership performs periodic credit evaluations of its customers' financial condition and generally does not require collateral for its accounts receivables. In some cases, the Partnership requires payment in advance or security in the form of a letter of credit or bank guarantee.

Cash Equivalents

For purposes of the consolidated statements of cash flows, the Partnership considers all highly liquid short-term investments with original maturities of three months or less to be cash equivalents.

Accounts Receivable

Crude oil sales receivable relate to the Partnership's gathering and marketing activities. The Partnership's gathering and marketing activities can generally be described as high volume and low margin activities. Transportation and storage accounts receivable are from shippers who transport crude on our pipelines and customers who lease our storage capacity. The Partnership makes a determination of the amount, if any, of credit to be extended to any given customer and the form and amount of financial performance assurances required. Such financial assurances are commonly provided in the form of standby letters of credit. The Partnership also monitors changes in the creditworthiness of its customers as a result of developments related to each customer, the industry as a whole and the general economy.

The Partnership routinely reviews its accounts receivable balances to identify past due amounts and analyze the reasons such amounts have not been collected. In many instances, such delays involve billing discrepancies or disputes as to the appropriate price, volumes or quality of crude oil delivered or exchanged. The Partnership has an insignificant amount for allowances for doubtful accounts as of December 31, 2005, 2004 and 2003.

Crude Oil and Refined Products Inventories

Crude oil and refined products inventories are valued at the lower of cost or market with cost determined using an average cost method. The inventory balance is subject to downward adjustment if prices decline below the carrying value of the inventory.

Property and Equipment

The components of property and equipment are capitalized at cost and depreciated using the straight-line method over the estimated useful lives of the assets as follows:

Pipelines	40 years
Tanks	40 years
Station and pumping equipment	10-20 years
Buildings	20-30 years
Other	3-15 years

In accordance with our capitalization policy, costs associated with acquisitions and improvements, including related interest costs, which expand our existing capacity are capitalized. For the years ended December 31, 2005 and 2004, and 2003, capitalized interest was $1.1 million, $0.4 million, and $0.1 million, respectively. In addition, costs incurred to extend the useful lives of assets are capitalized. Repair and maintenance expenditures associated with existing assets that do not extend the useful life or expand the operating capacity are charged to expense as incurred.

Impairment of Long-Lived Assets

Long-lived assets are reviewed for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. This review consists of a comparison of the carrying value of the asset with the asset's expected future undiscounted cash flows. Estimates of expected future cash flows represent management's best estimate based on reasonable and supportable assumptions and projections. If the expected future cash flows exceed the carrying value of the asset, no impairment is recognized. If the carrying value of the asset exceeds the expected future cash flows, impairment exists and is measured by the excess of the carrying value over the estimated fair value of the asset. Any impairment provisions are permanent and may not be restored in the future. The Partnership recorded impairment expense of $0.5 million and $0.8 million associated with idle Pacific Terminals property in 2005 and 2004, respectively.

Asset Retirement Obligations

The Partnership has determined that it is obligated by contractual or regulatory requirements to remove facilities or perform remediation upon retirement of certain of its assets. However, the Partnership is not able to reasonably determine the fair value of the asset retirement obligations for its pipelines and storage tanks, since the range of future dismantlement and removal dates are indeterminate.

In order to determine a removal date for the Partnership's gathering lines and related surface assets, reserve information regarding the production life of the specific field is required. The Partnership is not a producer of the oil field reserves, and therefore does not have access to adequate forecasts that predict the timing of expected production for existing reserves on those fields in which the Partnership gathers crude oil. In the absence of such information, the Partnership is not able to make a reasonable estimate of when the dismantlement and removal of its gathering assets will be required. With regard to the Partnership's trunk and interstate pipelines and their related surface assets, it is not possible to predict when demand for transportation of the related products will cease. The Partnership's right-of-way agreements allow it to maintain the right-of-way rather than remove the pipe. In addition, the Partnership believes its trunk pipelines can be put into alternative uses.

The Partnership will record such asset retirement obligations in the period in which sufficient information becomes available for it to reasonably estimate the settlement date and amount of its retirement obligations.

Investment in Frontier

The Partnership's 22% investment in Frontier is accounted for using the equity method of accounting. Under the equity method, an investment is initially recorded at cost and subsequently adjusted to recognize the investor's share of distributions and net income or losses of the investee as they occur. Recognition of any such losses is generally limited to the extent of the investor's investment in, advances to, and commitments and guarantees for the investee.

Deferred Financing Costs

Costs incurred in connection with the issuance of long-term debt are capitalized and amortized using the effective interest method. Costs incurred in connection with the issuance and amendments to our credit facilities are capitalized and amortized using the straight line methods over the term of the related facility. Unamortized debt issue costs may be written-off in conjunction with the refinancing or termination of the applicable debt arrangement prior to its scheduled maturity. We capitalized $7.9 million and $5.9 million of such costs in 2005 and 2004, respectively. In addition, during 2004 we wrote off $2.3 million of unamortized costs relating to the early termination of debt.

Environmental Liabilities

The Partnership accrues environmental remediation costs for work at identified sites where an assessment has indicated that cleanup costs are probable in the future and can be reasonably estimated. To the extent environmental liabilities are assumed in acquisitions, the Partnership records an estimate of such costs at the date of acquisition. These accruals are undiscounted and are based on information currently available, existing technology, the estimated timing of remedial actions and related inflation assumptions and enacted laws and regulations. The Partnership monitors the balance of accrued undiscounted environmental liabilities on a regular basis and may make adjustments to the initial estimates recorded, from time to time, to reflect changing circumstances.

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. The Partnership's Canadian subsidiaries are taxable entities in Canada and are subject to Canadian federal and provincial income taxes and other Canadian income taxes. In addition, monies repatriated by the Partnership from Canada into the U.S. may subject the Partnership to withholding taxes.

Net income for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under the Partnership's First Amended and Restated Agreement of Limited Partnership, as amended. Individual unitholders have different investment bases depending upon the timing and price of their acquisition of partnership units. Further, each unitholder's tax accounting, which is partially dependent upon the unitholder's tax position, differs from the accounting followed in the consolidated financial statements. Accordingly, the aggregate difference in the basis of the Partnership's net assets for financial and tax reporting purposes cannot be readily determined because information regarding each unitholder's tax attributes in the Partnership is not available to the Partnership.

In addition to federal and state income taxes, unitholders may be subject to other taxes, such as local, estate, inheritance or intangible taxes which may be imposed by the various jurisdictions in which the Partnership does business or owns property. Individual unitholders generally have no responsibility to file Canadian tax returns.

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.

Derivative Instruments

The Partnership uses certain derivative instruments to hedge its exposure to commodity price, interest rate and foreign exchange rate risks. The Partnership records all derivative instruments on the balance sheet as either assets or liabilities measured at their fair value under the provisions of Statement of Financial Accounting Standards No. 133 ("SFAS 133"), "Accounting for Derivative Instruments and Hedging Activities", as amended. SFAS 133 requires that changes in the fair value of derivative instruments be recognized currently in earnings unless specific hedge accounting criteria are met, in which case changes in fair value are deferred to "accumulated other comprehensive income" and reclassified into earnings when the underlying transaction affects earnings. Accordingly, changes in fair value are included in the current period for (i) derivatives characterized as fair value hedges, (ii) derivatives that do not qualify for hedge accounting and (iii) the portion of cash flow hedges that are not highly effective in offsetting changes in cash flows of hedged items. (See "Note 16—Derivative Financial Instruments" for further discussion).

The Partnership formally documents at inception the hedging relationship and its risk management objective and strategy for undertaking the hedge, the hedging instrument used, the nature of the risk being hedged, how the hedging instrument's effectiveness in offsetting the hedged risk will be assessed and the method of measuring such ineffectiveness. On a continuing basis, the Partnership assesses whether the derivative instruments that are used as hedges are highly effective in offsetting changes in fair values or cash flows that are being hedged. If it is determined that a derivative instrument ceases to be a highly effective hedge, then the Partnership will discontinue hedge accounting prospectively.

Foreign Currency Translation

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

Net Income per Unit

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

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

	Year Ended December 31,		
	2005	2004	2003
		(in thousands)	
Basic weighted average limited partner units	32,381	28,406	22,328
Effect of restricted units	23	67	202
Effect of unit options	10	15	10
Diluted weighted average limited partner units	32,414	28,488	22,540

Allocation of Net Income

Net income is allocated to the Partnership's general partner and limited partners based on their respective interests in the Partnership. The Partnership's general partner has also been directly charged with specific costs that it assumed in connection with its acquisition by LBP and for which neither the Partnership nor the limited partners are responsible (see "Note 17—Allocation of Net Income").

Restricted Units and Unit Options

As permitted under Statement of Financial Accounting Standards No. 123 ("SFAS 123"), "Accounting for Stock-Based Compensation," the Partnership elected to measure costs for restricted units and unit options using the intrinsic value method, as prescribed by Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees." Compensation expense related to the restricted units is recognized by the Partnership over the vesting periods of the units. Accordingly, the compensation expense related to the restricted units that is allocable to the current reporting period has been recognized in the accompanying consolidated statements of income, and non-cash employee compensation related to the long-term incentive plan is included in "undistributed employee long-term incentive compensation" in the accompanying consolidated balance sheets. No compensation expense related to the unit options has been recognized in the accompanying consolidated financial statements. Had the Partnership determined compensation cost based on the fair value at the grant date for its unit options under SFAS 123, "Accounting for Stock-Based Compensation," net income would have been reduced less than $0.1 million in each of 2005, 2004 and 2003 and the effect on earnings per limited partner unit would have been less than $0.01 per limited partner unit in each of 2005, 2004 and 2003.

Recent 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. There were no stock options or restricted stock units outstanding as of December 31, 2005 (see "Note 18—Long-Term Incentive Plan"). The Partnership will adopt SFAS 123R on January 1, 2006 for future grants.

In December 2004, the FASB issued Statement of Financial Accounting Standards No. 153, *Exchanges of Nonmonetary Assets* ("SFAS 153"). SFAS 153 addresses the measurement of exchanges of certain nonmonetary assets (except for certain exchanges of products or property held for sale in the ordinary course of business). It amends APB Opinion No. 29, *Accounting for Nonmonetary Exchanges*, and requires that nonmonetary exchanges be accounted for at the fair value of the assets exchanged, with gains or losses being recognized, if the fair value is determinable within reasonable limits and the transaction has commercial substance, as defined in SFAS 153. The Partnership adopted SFAS 153 on July 1, 2005, and the adoption did not have a material impact on the consolidated financial statements.

On March 30, 2005 the FASB issued FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations*("FIN 47"), to clarify the term *conditional asset retirement obligation* as that term is used in FASB Statement No. 143, *Accounting for Asset Retirement Obligations*. The Interpretation also clarifies when an entity has sufficient information to reasonably estimate the fair value of an asset retirement obligation. FIN 47 was effective for us as of December 31, 2005. The adoption of FIN 47 did not have a material impact on the Partnership's financial statements.

In May 2005, the FASB issued Statement of Financial Accounting Standards No. 154, *Accounting Changes and Error Corrections* ("SFAS 154"). SFAS 154 replaces APB No. 20, *Accounting Changes,* and FASB Statement No. 3, *Reporting Changes in Interim Financial Statements.* The Statement changes the accounting for, and reporting of, a change in accounting principle. SFAS 154 requires retrospective application to prior period's financial statements of voluntary changes in accounting principle and changes required by new accounting standards when the standard does not include specific transition provisions, unless it is impracticable to do so. SFAS 154 is effective for accounting changes and corrections of errors in fiscal years beginning after December 15, 2005. If required, the Partnership will apply the provisions of SFAS 154 in future periods.

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 Partnership is in the process of determining the impact of EITF 04-13 on its financial statements, but does not expect it to have a material impact on its financial statements.

3. ACQUISITIONS

Acquisition Of Assets From Valero, L.P.

On September 30, 2005, the Partnership completed the purchase of certain terminal and pipeline assets from various subsidiaries of Valero, L.P. (the "Sellers") for an aggregate purchase price of $455.0 million, plus $11.5 million for the assumption of certain legal, environmental and operating liabilities and $3.7 million for closing costs (the "Valero Acquisition"). Valero, L.P. was required to divest these assets pursuant to an order from the Federal Trade Commission in connection with its acquisition of the Kaneb group of companies. The purchased assets consist of (i) the Martinez and Richmond terminals in the San Francisco, California area, (ii) the North Philadelphia, South Philadelphia and Paulsboro, New Jersey, terminals in the Philadelphia, Pennsylvania area, and (iii) a 550-mile refined products pipeline with four terminals in the U.S. Rocky Mountains (the "Valero Assets"). The Valero Acquisition was funded through a combination of the proceeds from a private placement of 4.3 million common units, a public equity offering of 5.2 million common units, a private placement of $175 million of senior unsecured notes, and borrowings under the Partnership's new revolving credit facility (See "Note 9—Long-term Debt" and "Note 15—Partner's Capital" for further discussion on these financing arrangements).

The Martinez and Richmond terminals currently have 4.1 million barrels of combined storage capacity. The terminals handle refined products, blend stocks and crude oil, and are connected to a network of owned and third-party pipelines that carry crude oil and light products to and from area refineries. These terminals also receive and deliver crude oil and light products by marine vessel or barge. The Richmond terminal has a rail spur for delivery and receipt of light products and a truck rack for product delivery.

The North Philadelphia, South Philadelphia and Paulsboro terminals handle refined products and have a combined storage capacity of 3.1 million barrels. The terminals receive product via connections to third party pipelines and have truck racks for deliveries. The North Philadelphia and Paulsboro terminals can also deliver and receive products by marine vessel or barge.

The 550-mile Rocky Mountain Products Pipeline, formerly known as the West Pipeline System, consists of 550 miles of pipeline extending from Casper, Wyoming, east to Rapid City, South Dakota, and south to Colorado Springs, Colorado. There are products terminals at Rapid City, South Dakota, Cheyenne, Wyoming, and Denver and Colorado Springs, Colorado, with a combined storage capacity of 1.7 million barrels. The pipeline system has various segments with different receipt and delivery points.

The majority of the Rocky Mountain Products Pipeline was constructed in 1948, with extensions to Rapid City and Colorado Springs added in the 1960's. The South Philadelphia Terminal was constructed in 1938, the Richmond and Paulsboro terminals were constructed in 1953, and the Martinez and North Philadelphia terminals were constructed in 1973. Many improvements and facility additions have been made since the original startup of the operations. Additional tankage has been constructed and pipeline system and terminal improvements have been made over the years since their initial startup.

The Partnership has integrated the operations, maintenance, marketing and business development of the Rocky Mountain Products Pipeline with its existing pipeline activities in the Rocky Mountain Business Unit. It has similarly integrated the San Francisco area and Philadelphia area terminals with its existing pipeline and terminal activities in its West Coast Business Unit.

The Partnership did not acquire accounting software or hardware with the acquired assets. The Partnership has acquired and is implementing software associated with the complex task of volumetric and revenue accounting for the acquired assets, and uses its existing financial accounting software for other accounting functions. In addition, the Partnership did not acquire the pipeline control center or the software and other operating systems required for the Rocky Mountain Products Pipeline, and has installed new operating systems that are now being operated out of its Long Beach pipeline control center. The Seller agreed to provide all of these accounting, control center and operating services to the Partnership on a transition basis.

The acquired assets comprise only a portion of the total pipeline and terminal assets owned and operated by the Sellers in North America. The Sellers have other substantial pipeline and terminal assets that the Partnership did not acquire that are, or have been, operated and managed by the Seller's existing management team and operating and marketing staff. The acquired assets were not historically operated by the Sellers as a separate division or subsidiary. The Sellers, and prior to its merger with Valero, L.P., Kaneb Pipeline Partners, L.P. ("Kaneb"), operated these assets as part of its more extensive transportation and terminalling and refined products operations. As a result, neither the Sellers nor Kaneb maintained complete and separate financial statements for these assets as an independent business unit. The Partnership is making significant changes to the assets, and intends additional changes in the future, resulting in significant differences in operations and revenue generation. Additionally, differences in the Partnership's operating and marketing approach may result in it obtaining different productivity levels, results of operations and revenues than those historically achieved by the Sellers and Kaneb.

At the closing of the acquisition, the Partnership hired 76 of the Seller's employees directly involved in the operation of the acquired assets, including certain field level managerial and supervisory employees, operators, technicians, and engineers/project coordinators. The Partnership has hired additional accounting, environmental, engineering, pipeline controllers and technical staff to support the acquired assets.

The acquisition was accounted for as an acquisition of assets, and not as an acquisition of a continuing business operation.

The consolidated statements of income include the results of the acquired assets from their acquisition date. Based upon independent appraisals of the fair values of the acquired assets, the following is a summary of the consideration paid and purchase price allocation (in thousands):

Consideration and assumed liabilities:		
Purchase price	$	455,000
Transaction costs		3,740
Assumed liabilities		11,524
Total consideration and assumed liabilities	$	470,264

Purchase price allocation:		
Land and improvements	$	41,672
Storage tanks, pipelines and related equipment		396,696
Inventory		176
Intangible assets		31,720
Total	$	470,264

The Partnership is depreciating the purchased assets over their estimated useful lives of three to forty years based on the type of assets, which lives are similar to the Partnership's existing assets. Intangible assets are amortized over their estimated useful lives, which range from 15 to 40 years.

Purchase Of Crude Oil and Contracts

On July 1, 2005, Pacific Marketing and Transportation LLC, a wholly owned subsidiary of the Partnership, purchased certain crude oil contracts and crude oil inventories for approximately $3.8 million plus contingent payments over the next three and one-half years based on specified performance criteria. The Partnership will capitalize any such contingent payments as intangible assets and amortize them over three years.

Canadian Acquisitions

On May 11, 2004, the Partnership completed the acquisition of all of the outstanding shares of Rangeland Pipeline Company ("RPC"), Rangeland Marketing Company ("RMC") and Aurora Pipeline Company Ltd. ("Aurora"), the corporations that owned various components of the Rangeland system and the related marketing business from BP Canada Energy Company ("BP"). The Rangeland system is located in the province of Alberta, Canada. The purchase price for the shares of these companies was Cdn$130.1 million plus approximately Cdn$32.2 million for assumed liabilities, linefill, working capital and transaction costs. The aggregate purchase price was approximately U.S. $118.1 million and was funded through a combination of proceeds from the Partnership's March 30, 2004 equity offering and borrowings of Cdn$45 million. The acquisition was accounted for as an acquisition of assets.

On June 30, 2004, the Partnership completed the acquisition of the MAPL pipeline from Imperial Oil. The MAPL pipeline is located in Alberta, Canada, and connects with the Rangeland pipeline system. The purchase price for MAPL was Cdn$31.5 million, of which Cdn$5.0 million is payable June 30, 2007. In addition to the MAPL pipeline, the Partnership acquired linefill for Cdn$5.0 million. The aggregate purchase price, including assumed liabilities, linefill and transaction costs was approximately U.S. $27.0 million, most of which was funded from the Partnership's credit facility.

Following the acquisition, the MAPL pipeline assets were integrated into and are now operated as part of the Rangeland system.

Based upon independent appraisals of the fair values of the Rangeland and MAPL assets, the following is a summary of the consideration paid and purchase price allocation (U.S.$ in thousands):

Consideration and assumed liabilities:		
Purchase price	$	114,595
Payments for working capital, linefill, minimum tank inventories and other items		22,486
Transaction costs		1,620
Assumed liabilities		6,486
Subtotal		145,187
Deferred tax liability assumed		30,348
Total consideration and assumed liabilities	$	175,535
Purchase price allocation:		
Pipelines, equipment and property	$	120,838
Pipeline linefill and minimum tank inventories		17,620
Intangible assets		32,392
Working capital		4,685
Total	$	175,535

Pacific Terminals Storage and Distribution System

On July 31, 2003, PT completed the acquisition of the storage and pipeline distribution system assets of Edison Pipeline and Terminal Company, a division of Southern California Edison Company. The PT storage and distribution system is used by the Partnership to serve the crude oil and other dark products storage and distribution needs of the refining, pipeline, and marine terminal industries in the Los Angeles Basin. The purchase was funded through $90.0 million of proceeds from the issuance of additional common units on August 25, 2003, and borrowings under the Partnership's revolving credit facility, and was treated as an asset purchase. Based upon independent appraisals of the fair values of the acquired assets, the following is a summary of the consideration paid and purchase price allocation (in thousands):

Consideration and assumed liabilities:		
Purchase price	$	158,200
Payments for working capital and reimbursement of certain other expenditures		9,746
Transaction costs		1,524
Assumed liabilities		3,550
Total consideration and assumed liabilities	$	173,020
Purchase price allocation:		
Land	$	63,943
Storage tanks, pipelines and other equipment		103,783
Displacement oil, minimum tank inventories, spare parts and other		4,484
Intangible assets		810
Total	$	173,020

4. LINE 63 OIL RELEASE RESERVE

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 induced 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 $25.6 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 December 31, 2005, the Partnership had incurred approximately $19.0 million of the total expected remediation costs related to the oil release for work performed through that date. The Partnership estimates that $4.4 million of the remaining remediation costs will be incurred in 2006 and $2.2 million (included in "Other liabilities" in the accompanying balance sheet) will be incurred in 2007. Additionally, in 2005 the Partnership expensed $0.7 million for the repair of Line 63 and incurred $2.2 million of Line 63 capital improvements.

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 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. The Partnership's insurance coverage will not cover the cost to repair the pipeline. As of December 31, 2005, the Partnership has recovered $12.3 million from insurance and recorded receivables of $11.3 million for future insurance recoveries it deems probable, of which $2.2 million is considered long-term and is included in "Other assets, net" in the accompanying consolidated balance sheet.

The Partnership recorded $2.0 million in net costs in "Line 63 oil release costs" in the accompanying condensed consolidated financial statements for the year ended December 31, 2005. The $2.0 million net oil release costs consist of the $25.6 million of accrued costs relating to the release, net of insurance recovery of $12.3 million and accrued insurance receipts of $11.3 million.

Effective August 1, 2005, with the California Public Utilities Commission (the "CPUC") approval, the Partnership began collecting a temporary surcharge of $0.10 per barrel on its Line 63 long-haul tariff rates to recover its uninsured costs relating to this release together with other costs incurred or to be incurred as a result of problems caused by rain-related earth movement and stream erosion. The Partnership was required under the terms of the CPUC decision that approved the collection of the surcharge, to substantiate in subsequent advice letter filings with the CPUC that the actual costs incurred by the Partnership were necessary and reasonable and otherwise recoverable. The Partnership filed its advice letter on January 27, 2006, which was approved by the CPUC on February 22, 2006.

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. As new information becomes available in future periods, the Partnership may change its provision and recovery estimates.

5. PROPERTY AND EQUIPMENT

Property and equipment consists of the following amounts:

	December 31, 2005	December 31, 2004
	(in thousands)	
Pipelines and tanks	$ 922,946	$ 578,540
Land and land improvements	105,941	73,068
Station and pumping equipment	117,991	75,641
Buildings	15,736	13,580
Other	33,224	26,511
Construction in progress	75,568	15,998
	1,271,406	783,338
Less accumulated depreciation	(120,003)	(92,526)
	1,151,403	690,812
Displacement oil, pipeline linefill and minimum tank inventory	34,131	27,812
	$ 1,185,534	$ 718,624

Depreciation expense for each of the three years in the period ended December 31, 2005, was $27.4 million, $23.4 million and $18.2 million, respectively.

6. INTANGIBLE ASSETS

SFAS 142 requires that intangible assets with finite useful lives be amortized over their respective estimated useful lives. If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset shall be amortized over the best estimate of its useful life. The Partnership assesses the useful lives of all intangible assets each reporting period to determine if adjustments are required. All of the Partnership's intangibles have finite lives and are amortized on a straight line basis over the expected lives of the intangibles. The weighted average expected life of intangibles at December 31, 2005 and 2004 was approximately 31.0 years and 38.5 years, respectively. Amortization expense on amortizable intangible assets was $2.0 million, $0.8 million and $0.6 million for the years ended December 31, 2005, 2004 and 2003, respectively. Intangible assets included in the accompanying balance sheet consist of the following:

	December 31, 2005	December 31, 2004
	(in thousands)	
Customer relationships and contracts	$ 59,459	$ 37,788
Environmental permits	9,588	—
Assembled workforce	2,083	—
Other intangibles	1,572	1,572
	72,702	39,360
Less accumulated amortization	(3,522)	(1,466)
	$ 69,180	$ 37,894

The following table sets forth future estimated amortization expense on amortizable intangible assets as follows (in thousands):

Years ending December 31,		
2006	$	2,966
2007		2,747
2008		2,747
2009		2,723
2010		2,718
Thereafter		55,279
	$	69,180

7. INVESTMENT IN FRONTIER

RPL owns a 22.22% partnership interest in Frontier which is accounted for by the equity method of accounting. The summarized balance sheets and income statements are presented below (unaudited):

Balance Sheets

	December 31,			
	2005		2004	
	(in thousands)			
ASSETS				
Current assets	$	2,644	$	2,785
Property and equipment, net		10,411		9,110
	$	13,055	$	11,895
LIABILITIES AND PARTNERS' CAPITAL				
Current liabilities	$	572	$	1,257
Other liabilities		1,881		2,020
Partners' capital		10,602		8,618
	$	13,055	$	11,895

Statements of Income

	Year Ended December 31,					
	2005		2004		2003	
	(in thousands)					
Revenue	$	11,819	$	11,268	$	9,775
Operating expense		(3,702)		(4,270)		(3,644)
Depreciation expense		(377)		(368)		(364)
Operating income		7,740		6,630		5,767
Rate case and litigation expense		—		—		(7,295)
Other income (expense)		169		(14)		157
Net income (loss)	$	7,909	$	6,616	$	(1,371)

The unamortized portion of the excess cost over the Partnership's share of net assets of Frontier was $6.2 million and $6.3 million at December 31, 2005 and 2004, respectively. This excess cost over the Partnership's share of net assets represents the difference between the historical cost and the fair value of property and equipment at acquisition dates. The Partnership is amortizing this excess cost over the life of the related property and equipment.

8. RELATED PARTY TRANSACTIONS

Sale of The *Anschutz* Corporation's Interest in the Partnership

On March 3, 2005, Anschutz sold all of its interest in Pacific Energy GP, Inc. to LBP, which was formed by LBMB in connection with the purchase. The acquisition by LBP (the "LB Acquisition") included the 100% ownership interest in Pacific Energy GP, Inc., which owned (i) the 2% general partner interest in the Partnership and the incentive distribution rights, and (ii) 10,465,000 subordinated units of the Partnership which represented a then 34.6% limited partner interest in the Partnership. Immediately prior to the closing of the LB Acquisition, Pacific Energy GP, Inc. was converted to Pacific Energy GP, LLC, a Delaware limited liability company; and immediately after the closing of the LB Acquisition, Pacific Energy GP, LLC was converted to Pacific Energy GP, LP (the "General Partner"). Immediately following the consummation of the LB Acquisition, the General Partner distributed the 10,465,000 subordinated units of the Partnership to LBP.

In connection with the conversion of the Partnership's General Partner to a limited partnership, the General Partner ceased to have a board of directors, and is now managed by its general partner, Pacific Energy Management LLC, a Delaware limited liability company ("PEM" or the "Managing General Partner"), which is 100% owned by LBP. PEM has a board of directors (the "Board of Directors" or "Board") that manages the business and affairs of PEM and, thus, indirectly manages the business and affairs of the General Partner and the Partnership. All of the officers and employees of Pacific Energy GP, Inc. were transferred to fill the same positions with PEM, and the PEM Board established the same committees as had been maintained by Pacific Energy GP, Inc. prior to the LB Acquisition. PEM also adopted Pacific Energy GP, Inc.'s governance guidelines and its compensation structure and employee benefits plans and policies.

Additionally, on March 21, 2005, an affiliate of First Reserve Corporation ("First Reserve") acquired from LBMB a 30% partnership interest in LBP. LBMB and its affiliates continue to own a 70% partnership interest in LBP.

Lehman Brothers, Inc.

In connection with the purchase and associated financing of the Valero Acquisition including a private equity offering, public equity offering, senior notes offering and new credit facility, Lehman Brothers, Inc. and its affiliates provided advisory and underwriting services to the Partnership. Additionally, an affiliate of Lehman Brothers, Inc. was a participant in the syndicate that provided the Partnership's new senior secured credit facility. These agreements with Lehman Brothers, Inc. were reviewed and approved by the Conflicts Committee of the Board of Directors and the fees charged were customary for the types of services provided. For the period from March 3, 2005 through December 31, 2005, the Partnership incurred $9.9 million in fees with Lehman Brothers, Inc. and its affiliates, a portion of which was paid to non-affiliated financial institutions in the syndication of the New Credit Facility and in the public offering of equity.

Cost Reimbursements

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

Special Agreement: On March 3, 2005, Douglas L. Polson, previously the Chairman of the Board of Directors of Pacific Energy GP, Inc., 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 of Pacific Energy GP, Inc. 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 "Transaction costs" in the accompanying condensed consolidated income statements (see "Note 17—Allocation of Net Income"). LBP reimbursed this amount, which was recorded as a partner's capital contribution. Pursuant to the Consulting Agreement, Mr. Polson has agreed to perform advisory services to PEM from time to time as shall be mutually agreed between Mr. Polson and the Chief Executive Officer of PEM. In consideration for Mr. Polson's services under the Consulting Agreement, which has a one-year term, Mr. Polson receives 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.

LBP and Anschutz: LBP and Anschutz reimbursed the Partnership for certain other costs relating to the LB Acquisition. These included $1.2 million for the Consent Solicitation (as defined and further described in "Note 9—Long-Term Debt", below) and $0.3 million for legal and other expenses (also see "Note 17—Allocation of Net Income").

Other Related Party Transactions

Related party balances at December 31, 2005 and 2004 were as follows:

	December 31,	
	2005	2004
	(in thousands)	
Amounts included in accounts receivable:		
Anschutz and affiliates	$ —	$ 224
Frontier Pipeline Company	142	257
	$ 142	$ 481
Amounts included in due to related parties:		
Due to Pacific Energy GP, Inc.	$ —	$ 533

Prior to March 3, 2005, in the ordinary course of its operations, the Partnership engaged in various transactions with Anschutz and its affiliates. These transactions, which are more thoroughly described below, are summarized in the following table for the years ended December 31, 2005, 2004 and 2003:

	Year Ended December 31,		
	2005	2004	2003
	(in thousands)		
Revenue:			
Anschutz and affiliates	$ 79	$ 528	$ 1,120
Frontier Pipeline Company	782	880	575
General and administrative expense:			
Anschutz and affiliates	129	316	169
Crude oil purchases:			
Frontier Pipeline Company	1,355	—	—

Revenue from Related Parties

A subsidiary of Anschutz was a shipper on Line 2000 and was charged the published tariff rates applicable to "participating shippers" until March 31, 2003, when an agreement between the Anschutz subsidiary and a third party, the performance of which required the Anschutz subsidiary to ship on

Line 2000, was assigned to the Partnership for consideration equal to the value of transferred inventory. The agreement ended April 1, 2003. In addition, a subsidiary of Anschutz is a shipper on pipelines owned by RMPS and is charged published tariff rates.

RMPS serves as the contract operator for certain gas producing properties owned by a subsidiary of Anschutz in Wyoming and Utah, in exchange for which RMPS is reimbursed its direct costs of operation and is paid an annual fee of $0.3 million as compensation for the time spent by RMPS management and for other overhead services related to their activities. In addition, during 2003 and the first half of 2004, RMPS's trucking operation hauled water for a Anschutz subsidiary at rates equivalent to those charged to third parties.

RMPS also receives a management fee from Frontier in connection with time spent by RMPS management and for other services related to Frontier's pipeline's activities. RMPS received $0.8 million, $0.9 million and $0.6 million for the years ended December 31, 2005, 2004 and 2003, respectively.

Expenses Paid to Related Parties

Pursuant to an easement agreement between PPS and Union Pacific Corporation ("UPC"), UPC provides the Partnership with access to its right-of-way for a portion of Line 2000 in return for an annual rental. Philip F. Anschutz, a director of the Partnership's General Partner until March 3, 2005, and sole stockholder of Anschutz Company, the indirect parent until March 3, 2005, of the Partnership's General Partner, is a director of UPC.

From mid-2002 through December 31, 2005, the Partnership utilized a financial accounting system owned and provided by Anschutz under a shared services arrangement. In addition, the Partnership from time to time until mid-2003 utilized the services of Anschutz's risk management personnel for acquiring the Partnership's insurance, and the Partnership's surety bonds were, until 2004, issued under Anschutz's bonding line. From January 2003 through December 31, 2005, Anschutz charged the Partnership a fee of $0.1 million per year for these services and together with any out-of-pocket costs. The fixed annual fee included all license, maintenance and employee costs associated with our use of the financial accounting system.

In January 2003, the Partnership began leasing office space from an affiliate of Anschutz, for a term of five years at an initial annual cost of $0.1 million. The lease was terminated in February 2006.

9. LONG-TERM DEBT

The Partnership's long-term debt obligations are shown below:

	December 31,	
	2005	2004
	(in thousands)	
$400 million senior secured credit facility, bearing interest at 5.0% on December 31, 2005, due September 30, 2010	$ 140,751	$ —
Senior secured U.S. revolving credit facility, repaid and terminated on September 30, 2005	—	51,000
Senior secured Canadian revolving credit facility, repaid and terminated on September 30, 2005	—	54,005
$7^1/8$% senior notes, due June 2014, net of unamortized discount of $3,882 and $4,202 and including fair value increases of $567 and $2,693, respectively	246,684	248,491
$6^1/4$% senior notes, due September 2015, net of unamortized discount of $782	174,218	—
Future payment for MAPL assets, net of unamortized discount of $309 and $480, respectively	3,979	3,667
Total	565,632	357,163
Less current portion	—	—
Long-term debt	$ 565,632	$ 357,163

Principal payments due on long-term debt during each of the five years subsequent to December 31, 2005 are as follows (in thousands):

Year ending December 31,	
2006	$ —
2007	3,979
2008	—
2009	—
2010	140,751
Thereafter	420,902
Total	$ 565,632

$400 million Senior Secured Credit Facility

On September 30, 2005, the Partnership entered into a new five-year $400 million senior secured revolving credit facility (the "New Credit Facility") that replaced the Partnership's previous U.S. and Canadian revolving credit facilities. The New Credit Facility is available for general Partnership purposes in the U.S. and Canada, including working capital, letters of credit and distributions to unitholders (subject to certain limitations). The New Credit Facility matures on September 30, 2010, but the Partnership may prepay all loans under the New Credit Facility without premium or penalty. Obligations under the New Credit Facility are guaranteed by all of the subsidiaries of the Partnership except those for which regulatory approval is required and are secured by substantially all of the assets of the Partnership, excluding property held by the non-guaranteeing subsidiaries. The New Credit Facility is recourse to the Partnership and the guarantors, but non-recourse to the General Partner.

Subject to certain limited exceptions, indebtedness under the New Credit Facility bears interest (at the Partnership's option) at either (i) the base rate, which is equal to the higher of the prime rate as announced by Bank of America, N.A. or the Federal Funds rate plus 0.50% (or in the case of borrowings under the Canadian sub-facility described below, Canadian US dollar base rate or Canadian prime rate) each plus an applicable margin ranging from 0% to 0.75% or (ii) the Eurodollar rate plus an applicable margin ranging from 0.75% to 2.00%. The applicable margins fluctuate based on the Partnership's credit rating at any given time. In addition, the Partnership incurs a commitment fee which ranges from 0.1875% to 0.5000% per annum on the unused portion of the New Credit Facility.

Included in the New Credit Facility is a Canadian sub-facility for Rangeland Pipeline Company ("RPC"), one of the Partnership's Canadian subsidiaries. The Canadian sub-facility currently has a limit of U.S.$100 million, but can be adjusted from time to time by the Partnership. The Canadian sub-facility includes an option for RPC to receive loans in either U.S. dollars or Canadian dollars.

The New Credit Facility contains certain financial covenants and covenants limiting the ability of the Partnership to, among other things, incur or guarantee indebtedness, change ownership or structure, including mergers, consolidations, liquidations and dissolutions, sell or transfer assets and properties, and enter into a new line of business. At December 31, 2005, the Partnership was in compliance with all such covenants.

The Partnership provides certain suppliers with irrevocable standby letters of credit to secure its obligation for the purchase of crude oil. These letters of credit are issued under the Partnership's credit facility, and the liabilities with respect to these purchase obligations are recorded in "Accrued crude oil purchases" on the Partnership's balance sheet in the month the crude oil is purchased. Generally, these letters of credit are issued for up to sixty-day periods and are terminated upon completion of each transaction. In addition, the Partnership provided a letter of credit to the seller of the MAPL pipeline to secure a note payable. At December 31, 2005 and 2004, The Partnership had outstanding letters of credit totaling approximately $14.8 million and $4.2 million, respectively.

As of December 31, 2005, in addition to $14.8 million of letters of credit, $140.8 million was outstanding under the New Credit Facility, including $55.8 million under the Canadian sub-facility, and there was $125.5 million of undrawn available credit.

The New Credit Facility was entered into with a syndicate of financial institutions, including an affiliate of Lehman Brothers, Inc., which is an affiliate of LBP (see "Note 8—Related Party Transactions").

7^1/8% Senior Notes Due June 2014

On June 16, 2004, the Partnership and its 100% owned subsidiary, Pacific Energy Finance Corporation, completed the sale of $250 million of 7^1/8% senior unsecured notes due June 15, 2014. The notes were sold in a private offering to qualified institutional buyers in reliance on Rule 144A under the Securities Act of 1933 (the "Securities Act") and to non-U.S. persons under Regulation S of the Securities Act. In October 2004, the notes were exchanged for new notes with materially identical terms that have been registered under the Securities Act but are not listed on any securities exchange. The notes were issued at a discount of $4.4 million, resulting in an effective interest rate of 7.375%. Interest payments are due on June 15 and December 15 of each year. At any time prior to June 15, 2007, the Partnership has the option to redeem up to 35% of the aggregate principal amount of notes at a redemption price of 107.125% of the principal amount with the net cash proceeds of one or more equity offerings. The Partnership has the option to redeem the notes, in whole or in part, at anytime on or after June 15, 2009 at the following redemption prices:

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

The notes are jointly and severally guaranteed by certain of the Partnership's subsidiaries, namely Pacific Energy Group LLC, Pacific Marketing and Transportation LLC, Pacific Atlantic Terminals LLC, Rocky Mountain Pipeline System LLC, Ranch Pipeline LLC, PEG Canada GP LLC and PEG Canada, L.P.

The indenture governing the notes contains certain covenants that, among other things, limit the Partnership's ability and the ability of its restricted subsidiaries to incur or guarantee indebtedness or issue certain types of preferred equity securities; sell assets; pay distributions on, redeem or repurchase Partnership units; or consolidate, merge or transfer all or substantially all of its assets. At December 31, 2005, the Partnership was in compliance with all such covenants.

Under the indenture governing the Partnership's $7^1/8$% senior notes due 2014, the Partnership would have been required to make a "Change of Control Offer" to the holders of such notes if the LB Acquisition caused a rating decline by a credit rating agency. In order to avoid triggering the "Change of Control Offer" provision, the Partnership solicited the consent (the "Consent Solicitation") of the holders of the $7^1/8$% notes to amend certain provisions of the Indenture, including an amendment to the definition of "Change of Control." The Consent Solicitation was completed on February 10, 2005 with a majority of the holders of the senior notes consenting to the adoption of the proposed amendments, and as such, the proposed amendments were approved. Thereafter, a supplemental indenture that incorporated the proposed amendments was executed by the parties to the indenture. Fees of $0.6 million paid to holders of the notes were capitalized and included in "Other assets, net" in the accompanying condensed consolidated balance sheet at December 31, 2005 and are being amortized over the remaining life of the $7^1/8$% notes. Other solicitation-related fees and expenses of approximately $0.6 million are included in "Transaction costs" in the accompanying condensed consolidated statements of income. LBP and Anschutz reimbursed the Partnership for the entire cost of the Consent Solicitation, which reimbursement is recorded as a general partner's capital contribution (see "Note 8—Related Party Transactions").

$6^1/4$% Senior Notes Due 2015

On September 23, 2005, the Partnership and its 100% owned subsidiary, Pacific Energy Finance Corporation, completed the sale of $175 million of $6^1/4$% senior unsecured notes due September 15, 2015. The notes were sold in a private offering to qualified institutional buyers in reliance on Rule 144A under the Securities Act of 1933 and to non-U.S. persons under Regulation S of the Securities Act of 1933. In January 2006, the notes were exchanged for new notes with materially identical terms that have been registered under the Securities Act but are not listed on any securities exchange. The notes were sold for 99.544% of face value resulting in an effective interest rate of 6.3125% to maturity. Interest payments are due on March 15 and September 15 of each year, beginning on March 15, 2006.

The notes are jointly and severally guaranteed by the same Partnership subsidiaries that guarantee the $7^1/8$% senior notes, due June 2014. At any time prior to September 15, 2008, the Partnership has the option to redeem up to 35% of the aggregate principal amount of notes at a redemption price of 106.25% of the principal amount with the net cash proceeds of one or more equity offerings. At any time prior to September 15, 2010, the Partnership may redeem some or all of the notes at a price equal to 100% of the principal amount, plus a make-whole premium and accrued and unpaid interest, if any, to the date of redemption. The Partnership will also have the option to redeem the notes, in whole or in part, at any time on or after September 15, 2010 at the following redemption prices:

Year	Percentage
2010	103.125%
2011	102.083
2012	101.042
2013 and thereafter	100.000

The indenture governing the notes contains certain covenants that, among other things, limit the Partnership's ability and the ability of its restricted subsidiaries to incur or guarantee indebtedness or issue certain types of preferred equity securities; sell assets; pay distributions on, redeem or repurchase Partnership units; or consolidate, merge or transfer all or substantially all of its assets. At December 31, 2005, the Partnership was in compliance with all such covenants.

Net proceeds from the issuance of the notes were $170.9 million after deducting the $0.8 million discount and offering expenses of $3.3 million. The net proceeds were used to partially fund the Valero Acquisition.

Future Payment for MAPL Assets

In connection with the purchase of the MAPL pipeline, the Partnership is obligated to pay the seller Cdn$5.0 million (U.S.$4.3 million) on June 30, 2007. The future payment was discounted at 5%. The carrying value of the obligation was Cdn$4.4 million (U.S.$4.0 million) at December 31, 2005.

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

On June 16, 2004, in connection with the repayment of a term loan, the Partnership had a $2.3 million non-cash write-off of deferred financing costs and incurred a $0.6 million cash expense to terminate related interest rate swaps.

11. INCOME TAXES

In May 2004, the Partnership acquired the Rangeland Pipeline system (see "Note 3—Acquisitions"). The Partnership's 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 it unitholders. However, the Partnership's Canadian subsidiaries are taxable entities in Canada and are subject to Canadian federal and provincial income taxes. In addition, intercompany interest payments and repatriation of funds through dividends are subject to withholding tax.

Components of the income tax expense for the years ended December 31, 2005 and 2004 are as follows:

	Year Ended December 31,	
	2005	2004
	(in thousands)	
Current tax expense:		
Canadian federal and provincial income tax	$ (6)	$ 114
Capital tax	263	212
Withholding taxes	745	—
Other	250	—
Total	1,252	326
Deferred tax expense (benefit):		
Canadian federal and provincial income tax	(144)	(535)
Withholding taxes	55	470
Total	(89)	(65)
Total tax expense	$ 1,163	$ 261

The difference between the statutory federal income tax rate and the Partnership's effective income tax rate is summarized as follows:

	Year Ended December 31,	
	2005	2004
	(in thousands)	
Earnings before income tax	$ 40,811	$ 35,990
Federal income tax rate	35%	35%
Income tax at statutory rate	$ 14,284	$ 12,597
Increase (decrease) as a result of:		
Partnership earnings not subject to tax	(14,418)	(13,051)
Canadian withholding and capital taxes	1,063	682
Other	234	33
Total tax expense	$ 1,163	$ 261

Deferred tax assets and liabilities result from the following:

	December 31,	
	2005	2004
	(in thousands)	
Deferred tax assets:		
Book accruals in excess of current tax deductions	$ 1,198	$ 647
Net operating losses carried forward	2,941	2,312
Share and debt issue costs deductible in future years	15	21
Total deferred tax assets	4,154	2,980
Deferred tax liabilities:		
Canadian partnership income not currently taxable	3,092	1,926
Property, plant and equipment in excess of tax values	24,279	23,559
Intangible assets in excess of tax values	11,972	11,581
Withholding tax on future repatriation of income	582	470
Total deferred tax liabilities	39,925	37,536
Net deferred tax liabilities	$ 35,771	$ 34,556

The Partnership has $2.9 million of net operating loss carryforwards, of which $2.3 million will expire in the year 2014 and $0.6 million will expire in the year 2015. The Partnership believes it is more likely than not that the net operating loss carryforwards will be utilized prior to their expiration; therefore no valuation allowance is considered necessary.

12. ENVIRONMENTAL LIABILITIES

The Partnership is subject to numerous federal (U.S. and Canadian), state, provincial and local laws which regulate the discharge of materials into the environment or that otherwise relate to the protection of the environment. The following table presents the activity of the Partnership's environmental liabilities.

	December 31,	
	2005	2004
	(in thousands)	
Balance at beginning of year	$ 8,657	$ 5,486
Liabilities assumed in acquisitions	9,675	3,275
Additions charged to expense	267	—
Foreign currency translation adjustment	104	431
Expenditures	(371)	(535)
Balance at end of year	18,332	8,657
Less: current portion of environmental liabilities, included in "Other current liabilities"	(1,715)	(1,388)
Long-term portion of environmental liabilities	$ 16,617	$ 7,269

The actual future costs for environmental remediation activities will depend on, among other things, the identification of any additional sites, the determination of the extent of the contamination at each site, the timing and nature of required remedial actions, the technology available and required to meet the various existing legal requirements, the nature and extent of future environmental laws, inflation rates and the determination of the Partnership's liability at multi-party sites, if any, in light of uncertainties with respect to joint and several liability, and the number, participation levels and financial viability of other potentially responsible parties.

13. CONTINGENCIES

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 December 31, 2005) in general damages, Cdn$2 million (approximately U.S.$1.7 million at December 31, 2005) in special damages, and, in addition, unspecified amounts for punitive, exemplary and aggravated damages, costs and interest. The Statement of Claim has not been served on RPC, so RPC has not been required to file an answer. 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 Valero Acquisition, 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.

The Partnership is involved in various other regulatory disputes, litigation and claims arising out of its operations in the normal course of business (see also "Note 4—Line 63 Oil Release Reserve"). 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.

14. COMMITMENTS

Leases

The Partnership is obligated under several noncancelable operating leases, primarily for the rental of office space, trucks and equipment, which expire through the year 2011. These leases generally require the Partnership to pay all operating costs such as maintenance. Rental expense for all operating leases during the years ended December 31, 2005, 2004 and 2003 amounted to $1.9 million,

$1.5 million and $1.2 million, respectively. Future minimum rental payments under noncancelable operating leases at December 31, 2005 are as follows (in thousands):

Year ending December 31,	
2006	$ 1,378
2007	1,041
2008	761
2009	402
2010	174
Thereafter	28
	$ 3,784

Right-of-Way Obligations

The Partnership has secured various rights-of-way for the pipeline systems under right-of-way agreements that provide for annual payments to third parties. Right-of-way payments, which are included in operating expenses, totaled $3.3 million, $3.4 million and $2.9 million in 2005, 2004 and 2003, respectively.

The Partnership operates under various right-of-way and franchise agreements, certain of which expire at various times through at least 2035. Due to the nature of the Partnership's operations, the Partnership expects to continue making payments and renewing the right-of-way agreements. As of December 31, 2005, future minimum payments under the Partnership's right-of-way agreements of $4.0 million in 2006, between $4.5 million and $5.1 million annually in 2007 through 2010 and approximately $67.3 million thereafter reflect the Partnership's commitment for the next 15 years, assuming the current right-of-way agreements will be renewed during that period. The annual amounts payable under various right-of-way agreements are subject to adjustments as described above as well as for the effects of inflation, which is estimated at 5% per year.

15. PARTNERS' CAPITAL

Common Units Outstanding

There were 31,448,931 common units outstanding at December 31, 2005, with the public unitholders owning 28,832,681 units and LB Pacific, LP owning 2,616,250 units.

Subordinated Units and Conversion

All of the 7,848,750 subordinated units outstanding at December 31, 2005 were owned by LB Pacific, LP. The purpose of the subordinated units is to increase the likelihood that during the subordination period there will be available sufficient cash to pay the minimum quarterly distribution on the common units. The subordination period will generally expire on the first day of any quarter beginning after June 30, 2007 once certain financial tests are achieved. Prior to the end of the subordination period, 50% of the subordinated units (25% in respect of each quarter ending on or after June 30, 2005 and 2006) may convert into common units on a one-for-one basis. On August 12, 2005, pursuant to the terms of the Partnership's partnership agreement, 25% or 2,616,250 subordinated units were converted to common units on a one-for-one basis.

General Partner Interest

The Partnership's General Partner holds a 2% interest in the Partnership and is required to make additional capital contributions to the Partnership upon the issuance of any additional units, if necessary, to maintain its capital account balance equal to 2% of the total capital accounts of all partners.

Distributions

Within 45 days after the end of each quarter, the Partnership will distribute all of its available cash, if any, to unitholders of record on the applicable date and to its General Partner. Available cash is generally defined as all of the Partnership's cash and cash equivalents on hand at the end of each quarter less reserves established by the General Partner for future requirements. Cash distributions in each of the three years ended December 31, 2005 were as follows:

Year Ended December 31,	Common Units	Subordinated Units	General Partner Interest	Total
	(in thousands)			
2005	$ 45,458	$ 19,981	$ 1,336	$ 66,775
2004	34,981	20,407	1,130	56,518
2003	21,650	19,624	841	42,115

In January 2006, the Partnership declared a cash distribution of $0.555 per limited partner unit for the fourth quarter of 2005, which was paid in February 2006 to unitholders of record as of January 31, 2006.

The General Partner is entitled to incentive distributions in quarters when the limited partner distribution exceeds $0.5125 per unit. The February 2006 distribution was the first quarterly distribution to exceed $0.5125 per limited partner unit and, accordingly, the General Partner received an incentive distribution of approximately $255,000 in addition to its 2% interest distribution.

Public Equity Offerings

During the three years ended December 31, 2005, the Partnership completed the following public equity offerings of its common units:

Period	Units	Gross Unit Price	Proceeds from Sale	General Partner Contribution	Costs	Net Proceeds
		(in thousands, except units and per unit amounts)				
September 2005	5,232,500	$ 32.00	$ 167,440	$ 3,417	$ 7,619	$ 163,238
March/April 2004	4,625,000	28.50	131,813	2,690	5,932	128,571
August/September 2003	5,612,000	24.66	138,392	1,955	6,676	133,671

Net proceeds from the September 2005 offering were used to partially fund the Valero Acquisition. Net proceeds from the March/April 2004 offering were used to partially fund the Rangeland acquisition and to repay borrowings under the U.S. revolving credit facility. Proceeds from the 2003 offering were used to repay indebtedness outstanding under PEG's revolving credit facility, which had been incurred in connection with the acquisition of PT storage and distribution system assets and to redeem 1,727,100 common units owned by the General Partner.

Private Equity Placement

On September 30, 2005, the Partnership sold 4,300,000 common units pursuant to a Common Unit Purchase Agreement with certain institutional investors at a price of $30.75 per unit. The Partnership received net proceeds of $131.8 million from the sale of the common units including the General Partner's contribution of $2.7 million, which were used to partially fund the Valero Acquisition.

Shelf Registration Statements

On December 23, 2005, the Partnership and certain 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 the market conditions and needs of the Partnership, of up to $1.0 billion of common units of the Partnership and debt securities of both the Partnership and certain subsidiaries. The SEC declared the registration statement effective on January 12, 2006. In addition, we have $110 million available and remaining under our August 2003 universal shelf registration statement.

16. DERIVATIVE FINANCIAL INSTRUMENTS

The Partnership uses derivative financial instruments primarily to reduce its exposure to adverse fluctuations in commodity prices, interest rates and foreign exchange rates. The Partnership formally designates and documents such financial instrument as a hedge of a specific underlying exposure, as well as the risk management objectives and strategies for undertaking the hedge transactions. The Partnership 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 the Partnership's derivatives are commonly used over-the-counter instruments with liquid markets or are traded on the New York Mercantile Exchange. The Partnership does not enter into derivative financial instruments for trading or speculative purposes.

Commodity Price Risk Hedging

The Partnership uses derivative instruments (principally futures and options) to hedge its exposure to market price volatility related to its inventory or future sales of crude oil. Derivatives used to hedge market price volatility related to inventory are generally designated as fair value hedges, and derivatives related to future sale of crude oil are generally classified as cash flow hedges. Derivative instruments are included in other assets in the accompanying consolidated balance sheets.

Changes in the fair value of the Partnership's derivative instruments related to crude oil inventory are recognized in net income. For the years ended December 31, 2005, 2004 and 2003, "crude oil sales, net of purchases" were net of $0.8 million, $2.7 million and $0.3 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 the Partnership's derivative instruments related to the future sale of crude oil, which are generally for one year or less, are deferred and reflected in "accumulated other comprehensive income," a component of partners' capital, until the related revenue is reflected in the consolidated statements of income. As of December 31, 2005, a $0.1 million loss relating to the change in the fair value of highly effective derivative instruments was included in "accumulated other comprehensive income" and is expected to be reclassified to earnings in 2006. Since these amounts are based on market prices at the current period end, actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions. There were immaterial amounts of ineffectiveness associated with crude oil hedging in 2005, 2004 and 2003, respectively.

Interest Rate Risk Hedging

In connection with the issuance of its $7^1/8$% senior notes due 2014, the Partnership entered into interest rate swap agreements with an aggregate notional principal amount of $80.0 million to receive interest at a fixed rate of $7^1/8$% 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 in June 2014 and are callable at the same dates and terms as the $7^{1}/8$% senior notes. The Partnership designated these swaps as a hedge of the change in the Senior Notes fair value attributable to changes in the six month LIBOR interest rate. Changes in fair values of the interest rate swaps are recorded into earnings each period. Similarly, changes in the fair value of the underlying $80.0 million of senior notes, which are expected to be offsetting to changes in the fair value of the interest swaps, are recorded into earnings each period. At December 31, 2005, the Partnership recorded an increase of $0.6 million in the fair value of interest rate swaps. During the year ended December 31, 2005, the Partnership recognized reductions in interest expense of $1.3 million related to the difference between the fixed rate and the floating rate of interest on the interest rate swaps. As of December 31, 2005 and 2004, the Partnership had immaterial amounts of hedge ineffectiveness relating to these interest rate swaps.

In the third quarter of 2002, the Partnership entered into interest rate swap agreements that were to mature in 2007 and 2009 with a notional amount of $170.0 million. The Partnership designated these swaps as a hedge of its exposure to variability in future cash flows attributable to the LIBOR interest payments due on $170.0 million outstanding under a term loan facility. The average swap rate on this $170.0 million of debt was approximately 4.25%, resulting in an all-in interest rate on the $170.0 million of debt of approximately 6.50%. In June 2004, in conjunction with the issuance of the $7^{1}/8$% Senior Notes and the repayment of the term loan, the Partnership bought back the swaps for a loss of $0.6 million.

Currency Exchange Rate Risk Hedging

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

The Partnership 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 these contracts, which have been designated as a cash flow hedge, is reported in "Accumulated other comprehensive income" and will be reclassified into earnings in "Other income" in the period 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 are as follows:

	Canadian dollars	US dollars	Average Exchange Rate
	(in thousands)		
2006	$ 7,200	$ 6,126	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

As of December 31, 2005, a $0.2 million loss relating to foreign exchange contracts was deferred and included in "accumulated other comprehensive income" and is expected to be reclassified into earnings in 2006. For the year ended December 31, 2005, no gains or losses were recognized in the income statement for these foreign exchange contracts.

Credit Risks

By using derivative financial instruments to hedge exposures related to changes in commodity prices, interest rates and currency exchange rates, the Partnership exposes itself to market risk and credit risk. Market risk is the risk of loss arising from the adverse effect on the value of a financial instrument that results from 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 the Partnership, which creates credit risk for the Partnership. When the fair value of a derivative agreement is negative, the Partnership is liable to the counterparty and, therefore, it creates credit risk for the counterparty. The counterparties the Partnership transacts with are large, well known companies in the industry or large creditworthy financial institutions. As such, the Partnership believes its exposure to counterparty credit risk is low. Nonetheless, there can be no assurance as to the performance of a counterparty.

Fair Value of Financial Instruments

The carrying amount and fair values of financial instruments are as follows:

	December 31,			
	2005		2004	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(in thousands)			
Crude oil hedging futures	$ 161	$ 161	$ 400	$ 400
Fair value interest rate swaps	567	567	2,693	2,693
Foreign exchange contracts	195	195	—	—
Long-term debt	565,632	576,015	357,163	373,265

As of December 31, 2005 and 2004, the carrying amounts of items comprising current assets and current liabilities approximate fair value due to the short-term maturities of these instruments. The carrying amounts of the revolving credit facilities approximate fair value primarily because the interest rates fluctuate with prevailing market rates. The interest rates on the $7^1/8$% senior notes due 2014 and the $6^1/4$% senior notes due 2015 are fixed and the fair value is determined from a broker's price quote at December 31, 2005.

The carrying amount of derivative financial instruments represents fair value as these instruments are recorded on the balance sheet at their fair value under SFAS 133. The Partnership's fair values of crude oil hedging futures are based on Reuters quoted market prices on the NYMEX. Interest rate swaps and foreign exchange contracts fair values are based on the prevailing market price at which the positions could be liquidated.

17. ALLOCATION OF NET INCOME

The allocation of net income between the Partnership's General Partner and limited partners is as follows.

	Year Ended December 31,		
	2005	2004	2003
		(in thousands)	
Net income	$ 39,648	$ 35,729	$ 25,029
Transaction costs reimbursed by general partner:			
$7^{1}/8$% senior notes consent solicitation and other costs	893	—	—
Severance and other costs	914	—	—
Total transaction costs reimbursed by general partner	1,807	—	—
Income before transaction costs reimbursed by general partner	41,455	35,729	25,029
General partner's share of income	2%	2%	2%
General partner allocated share of net income before transaction costs	829	715	501
Transaction costs reimbursed by general partner	(1,807)	—	—
Net income (loss) allocated to general partner	$ (978)	$ 715	$ 501
Income before transaction costs reimbursed by general partner	$ 41,455	$ 35,729	$ 25,029
Limited partners share of income	98%	98%	98%
Limited partners share of net income	$ 40,626	$ 35,014	$ 24,528
Net income (loss) allocated to general partner	$ (978)	$ 715	$ 501
Net income allocated to limited partners	40,626	35,014	24,528
Net income	$ 39,648	$ 35,729	$ 25,029

LBP and Anschutz reimbursed the Partnership for certain costs incurred in connection with the LB 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 (see "Note 8—Related Party Transactions"), for a total of $2.4 million. Of the $1.2 million incurred for the consent solicitation, $0.6 million was capitalized as deferred financing costs (and did not affect the income allocation) and $0.6 million was expensed.

18. LONG-TERM INCENTIVE PLAN

In 2002, the General Partner adopted the Long-Term Incentive Plan (the "Plan") for employees and affiliates who perform services for the Partnership. The Plan consists of two components, a restricted unit plan and a unit option plan. The Plan was amended in 2006. The Plan currently permits the granting of an aggregate of 1,750,000 restricted units and unit options and is administered by the Compensation Committee of the Managing General Partner, subject to approval by the Managing General Partner's Board of Directors. The Managing General Partner's Board of Directors in its discretion may terminate the Plan at any time with respect to any restricted units for which a grant has not yet been made. The Managing General Partner's Board of Directors also reserves the right to alter or amend the Plan from time to time, including increasing the number of common units with respect to which awards may be granted; provided, however, that no change in any outstanding grant may be made which would materially impair the rights of the participant without the consent of such participant. As the restricted units vest, the Managing General Partner has the option to acquire common units in the open market for delivery to the recipient or distribute newly issued common units from the Partnership. In all cases, the Managing General Partner is reimbursed by the Partnership for such expenditures.

Restricted unit activity during the years ended December 31, 2005, 2004 and 2003 was as follows:

	Number of Restricted Units
Balance at December 31, 2002	381,250
Granted	34,000
Vested(1)	(130,750)
Forfeited	(12,500)
Balance at December 31, 2003	272,000
Granted	11,500
Vested(1)	(135,750)
Forfeited	(3,000)
Balance at December 31, 2004	144,750
Vested(1)	(144,750)
Balance at December 31, 2005	—

(1) Includes units relinquished in satisfaction of withholding taxes.

The Partnership recognized $0.2 million, $2.1 million and $3.2 million of compensation expense associated with these grants in 2005, 2004 and 2003.

On March 3, 2005, in connection with the LB Acquisition and the change in control of the Partnership's General Partner, all restricted units 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.

In addition, Canadian employees of the Partnership participate in a separate Phantom Unit Plan, which upon vesting provides for payment in cash for the equivalent of the Partnership's unit on the vesting date. In 2004, the General partner granted 15,000 phantom units to certain key employees which were to vest over five years from the date of grant. These phantom units also became immediately vested with the change in control of the Partnership's General Partner.

In December 2002, the General Partner granted 50,000 common unit options with a 10-year term. The unit options were granted with an exercise price of $19.50 per unit, which was equal to the fair market value at the date of grant and vested in 2003 and 2004. On July 8, 2005, these options were exercised, 8,149 common units were withheld to cover withholding taxes and the Partnership issued 41,851 new common units.

The Partnership applied APB Opinion No. 25, "Accounting for Stock Issued to Employees," and, accordingly, no compensation expense was recognized for its unit options in the financial statements.

In January 2006, the General Partner awarded restricted units to key employees that vest over a three-year period, beginning on March 1, 2006, and that are also subject to meeting annual financial performance objectives. The financial measure used is the Partnership's distributable cash flow per unit, as determined by the Compensation Committee, for the calendar year preceding each of the three annual vesting dates. The number of units to be delivered in any year, if any, will be a portion of the number vested on March 1 of that year based on accomplishment of performance targets for the previous calendar year. The Partnership will apply the accounting treatment under FAS 123R to these restricted units awards beginning on January 1, 2006.

19. EMPLOYEE BENEFIT PLANS

The General Partner sponsors a defined contribution 401(k) plan for its U.S. based employees whereby eligible employees may contribute up to 18% of their annual compensation to the plan, subject to certain defined limits. The General Partner matches employee contributions up to 6% to 12%, depending on years of service, of the employee's annual compensation. Total employer contributions to the plan were $1.0 million, $0.9 million and $1.0 million, for 2005, 2004 and 2003 respectively.

The Partnership's Canadian subsidiaries sponsor an employee savings plan (the "Savings Plan") and a defined contribution plan. Under the Savings Plan eligible employees may contribute a percentage of their salary to the Savings Plan. The Partnership's Canadian subsidiaries provide matching contributions between 1% and 6% depending on years of service. The defined contribution plan requires the Canadian subsidiaries to make a contribution to a tax-deferred account established in an employee's name. Employee contributions to the defined contribution plan are not required nor permitted. The Canadian subsidiaries make contributions of between 2% and 6% of an employee's annual compensation depending on years of service. Contributions are limited by the Canada Customs and Revenue Agency to Cdn$18,000 in 2006 for any employee. Total employer contributions to the plan for 2005 and 2004 were Cdn$0.4 million and Cdn$0.2 million.

20. 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, owner of the PMT gathering system, (iii) Pacific Terminals LLC, owner of the Pacific Terminals storage and distribution system, which was acquired on July 31, 2003, and (iv) Pacific Atlantic Terminals LLC, which was formed for the purpose of holding the California and East Coast terminal assets the Partnership acquired in the Valero Acquisition 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 in the Valero Acquisition on September 30, 2005, (ii) Ranch Pipeline LLC, the owner of a 22.22% partnership interest in Frontier Pipeline Company, and (iii) PEG Canada, L.P. and its Canadian subsidiaries, which own and operate the Rangeland system (which was acquired on May 11, 2004). 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 Operations	Rocky Mountain Operations	Intersegment and Intrasegment Eliminations	Total
		(in thousands)		
Year ended December 31, 2005				
Revenues:				
Pipeline transportation revenue	$ 63,006	$ 60,071	$ (6,429)	$ 116,648
Storage and terminaling revenue(1)	52,136	—	(150)	51,986
Pipeline buy/sell transportation revenue(2)	—	35,671		35,671
Crude oil sales, net of purchases(3)	19,809	374	(186)	19,997
Net revenue	134,951	96,116		224,302
Expenses:				
Operating	66,237	44,925	(6,765)	104,397
Line 63 oil release costs(4)	2,000	—		2,000
Depreciation and amortization	15,927	13,479		29,406
Total expenses	84,164	58,404		135,803
Share of net income of Frontier	—	1,757		1,757
Write-down of idle property	(450)	—		(450)
Operating income from segments(5)	$ 50,337	$ 39,469		$ 89,806
Identifiable assets(6)	$ 878,101	$ 549,244		$ 1,427,345
Capital expenditures(7)	$ 16,451	$ 26,571		$ 43,022
Year ended December 31, 2004				
Revenues:				
Pipeline transportation revenue	$ 67,173	$ 47,131	$ (5,909)	$ 108,395
Storage and terminaling revenue(1)	38,080	—	(503)	37,577
Pipeline buy/sell transportation revenue(2)	—	18,640		18,640
Crude oil sales, net of purchases(3)	16,907	—	(120)	16,787
Net revenue	122,160	65,771		181,399
Expenses:				
Operating	58,197	33,621	(6,532)	85,286
Depreciation and amortization	14,424	9,749		24,173
Total expenses	72,621	43,370		109,459
Share of net income of Frontier	—	1,328		1,328
Write-down of idle property	(800)	—		(800)
Operating income from segment(5)	$ 48,739	$ 23,729		$ 72,468
Identifiable assets(6)	$ 496,324	$ 341,706		$ 838,030
Capital expenditures(7)	$ 4,220	$ 6,949		$ 11,169

Year ended December 31, 2003				
Revenues:				
Pipeline transportation revenue	$ 67,946	$ 41,298	$ (7,433)	$ 101,811
Storage and terminaling revenue(1)	12,711	—		12,711
Crude oil sales, net of purchases(3)	21,293	—		21,293
Net revenue	101,950	41,298		135,815
Expenses:				
Operating	46,287	22,192	$ (7,433)	61,046
Depreciation and amortization	12,999	5,866		18,865
Total expenses	59,286	28,058		79,911
Share of net income of Frontier	—	(162)		(162)
Operating income from segment(5)	$ 42,664	$ 13,078		$ 55,742
Identifiable assets(6)	$ 509,137	$ 121,892		$ 631,029
Capital expenditures(7)	$ 4,023	$ 1,418		$ 5,441

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

(2) Includes the revenue of the Rangeland system, which was acquired on May 11, 2004 and June 30, 2004.

(3) The above amounts are net of purchases of $623,115, $402,283 and $358,454 for 2005, 2004 and 2003, respectively.

(4) See "Note 4—Line 63 Oil Release Reserve" for further information.

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

	2005	2004	2003
		(in thousands)	
Operating income from above:			
West Coast Operations	$ 50,337	$ 48,739	$ 42,664
Rocky Mountain Operations	39,469	23,729	13,078
Operating income from segments	89,806	72,468	55,742
Less: General and administrative expense	18,472	15,400	13,705
Less: Accelerated long-term incentive plan compensation expense	3,115	—	—
Less: Transaction costs	1,807	—	—
Operating income	66,412	57,068	42,037
Interest and other income	1,119	1,032	479
Interest expense	(26,720)	(19,209)	(17,487)
Write-off of deferred financing cost and interest rate swap termination expense	—	(2,901)	—
Income tax expense	(1,163)	(261)	—
Net income	$ 39,648	$ 35,729	$ 25,029

(6) Identifiable segment assets do not include assets related to the Partnership's corporate activity. As of December 31, 2005, 2004 and 2003, corporate related assets were $49,107, $31,875 and $19,174, respectively.

(7) Capital expenditures do not include the Pier 400 project and other parent-level related capital expenditures. Pier 400 project and other parent-level related capital expenditures were $8,695, $5,351, and $5,451 as of December 31, 2005, 2004, and 2003, respectively.

Geographic Data

Set forth below are revenues and identifiable assets attributable to the United States and Canada for the years ended December 31, 2005 and 2004:

	Year Ended December 31, 2005	Year Ended December 31, 2004
	(in thousands)	
Revenues:		
United States	$ 188,631	$ 162,759
Canada	35,671	18,640
	$ 224,302	$ 181,399

	December 31, 2005	December 31, 2004
	(in thousands)	
Total Assets:		
United States	$ 1,221,246	$ 658,594
Canada	255,206	211,311
	$ 1,476,452	$ 869,905

21. 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 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:

Balance Sheet
December 31, 2005

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
			(in thousands)		
Assets:					
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
Intangible assets	—	31,220	37,960	—	69,180
Intercompany notes receivable	661,313	340,905	—	(1,002,218)	—
Other assets	13,426	—	8,041	—	21,467
Total assets	$ 1,209,530	$ 1,292,151	$ 730,051	$ (1,755,280)	$ 1,476,452
Liabilities and partners' capital:					
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
Total partners' capital	698,239	429,802	189,083	(618,885)	698,239
Total liabilities and partners' capital	$ 1,209,530	$ 1,292,151	$ 730,051	$ (1,755,280)	$ 1,476,452

Balance Sheet
December 31, 2004

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
			(in thousands)		
Assets:					
Current assets	$ 14,869	$ 80,320	$ 41,948	$ (41,592)	$ 95,545
Property and equipment	—	129,496	589,128	—	718,624
Equity investments	366,148	194,787	—	(553,049)	7,886
Intangible assets	—	118	37,776	—	37,894
Intercompany notes receivable	283,550	338,884	—	(622,434)	—
Other assets	7,223	1,875	858	—	9,956
Total assets	$ 671,790	$ 745,480	$ 669,710	$ (1,217,075)	$ 869,905
Liabilities and partners' capital:					
Current liabilities	$ 833	$ 44,177	$ 44,627	$ (41,592)	$ 48,045
Long-term debt	248,491	51,000	57,672	—	357,163
Deferred income taxes	—	470	34,086	—	34,556
Intercompany notes payable	—	283,550	338,884	(622,434)	—
Other liabilities	—	135	7,540	—	7,675
Total partners' capital	422,466	366,148	186,901	(553,049)	422,466
Total liabilities and partners' capital	$ 671,790	$ 745,480	$ 669,710	$ (1,217,075)	$ 869,905

Statement of Income Year Ended December 31, 2005					
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands)				
Net operating revenues before expenses	$ —	$ 89,968	$ 141,099	$ (6,765)	$ 224,302
Operating expenses	—	(48,421)	(62,741)	6,765	(104,397)
Line 63 oil release costs	—	—	(2,000)	—	(2,000)
General and administrative expense(1)	—	(16,317)	(2,155)	—	(18,472)
Accelerated long-term incentive plan compensation expense	—	(2,675)	(440)	—	(3,115)
Transaction costs	(893)	(914)	—	—	(1,807)
Depreciation and amortization expense	—	(9,558)	(19,848)	—	(29,406)
Write-down of idle property	—	—	(450)	—	(450)
Share of net income of Frontier	—	1,757	—	—	1,757
Operating income	(893)	13,840	53,465	—	66,412
Interest expense	(21,191)	(2,418)	(3,111)	—	(26,720)
Intercompany interest income (expense)	—	25,910	(25,910)	—	—
Equity earnings	61,455	24,050	—	(85,505)	—
Interest and other income (expense)	277	1,123	(281)	—	1,119
Income tax benefit (expense)	—	(1,050)	(113)	—	(1,163)
Net income	$ 39,648	$ 61,455	$ 24,050	$ (85,505)	$ 39,648

Statement of Income Year Ended December 31, 2004					
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands)				
Net operating revenues before expenses	$ —	$ 64,038	$ 123,893	$ (6,532)	$ 181,399
Operating expenses	—	(40,257)	(51,561)	6,532	(85,286)
General and administrative expense(1)	—	(14,139)	(1,261)	—	(15,400)
Depreciation and amortization expense	—	(6,660)	(17,513)	—	(24,173)
Write-down of idle property	—	—	(800)	—	(800)
Share of net income of Frontier	—	1,328	—	—	1,328
Operating income	—	4,310	52,758	—	57,068
Interest expense	(8,752)	(8,493)	(1,964)	—	(19,209)
Write-off of deferred financing cost and interest rate swap termination expense	—	(2,901)	—	—	(2,901)
Intercompany interest income (expense)	—	20,429	(20,429)	—	—
Equity earnings	44,464	30,773	—	(75,237)	—
Interest and other income	17	816	199	—	1,032
Income tax benefit (expense)	—	(470)	209	—	(261)
Net income	$ 35,729	$ 44,464	$ 30,773	$ (75,237)	$ 35,729

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

	Statement of Income Year Ended December 31, 2003				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating adjustments	Total
	(in thousands)				
Net operating revenues before expenses	$ —	$ 62,589	$ 80,659	$ (7,433)	$ 135,815
Operating expenses	—	(38,663)	(29,816)	7,433	(61,046)
General and administrative expense(1)	—	(13,582)	(123)	—	(13,705)
Depreciation and amortization expense	—	(6,336)	(12,529)	—	(18,865)
Share of loss of Frontier	—	(162)	—	—	(162)
Operating income	—	3,846	38,191	—	42,037
Interest expense	—	(17,487)	—	—	(17,487)
Intercompany interest income (expense)	—	10,322	(10,322)	—	—
Equity earnings	25,010	27,907	—	(52,917)	—
Interest and other income	19	422	38	—	479
Net income	$ 25,029	$ 25,010	$ 27,907	$ (52,917)	$ 25,029

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

	Statement of Cash Flows Year Ended December 31, 2005				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
			(in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net income	$ 39,648	$ 61,455	$ 24,050	$ (85,505)	$ 39,648
Adjustments to reconcile net income to net cash provided by operating activities:					
Equity earnings	(61,455)	(24,050)	—	85,505	—
Distributions from subsidiaries	66,775	38,643	—	(105,418)	—
Depreciation, amortization and other	1,025	12,576	20,859	—	34,460
Net changes in operating assets and liabilities	4,555	(5,024)	7,255	(4,786)	2,000
NET CASH PROVIDED BY OPERATING ACTIVITIES	50,548	83,600	52,164	(110,204)	76,108
CASH FLOWS FROM INVESTING ACTIVITIES:					
Acquisitions	—	(462,553)	—	—	(462,553)
Additions to property, equipment and other	—	(18,565)	(31,633)	—	(50,198)
Intercompany	(465,466)	—	—	465,466	—
NET CASH USED IN INVESTING ACTIVITIES	(465,466)	(481,118)	(31,633)	465,466	(512,751)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	416,397	392,479	(22,334)	(355,262)	431,280
Effect of translation adjustment	—	—	44	—	44
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	1,479	(5,039)	(1,759)	—	(5,319)
CASH AND CASH EQUIVALENTS, beginning of year	2,713	17,523	3,147	—	23,383
CASH AND CASH EQUIVALENTS, end of year	$ 4,192	$ 12,484	$ 1,388	$ —	$ 18,064

	Statement of Cash Flows Year Ended December 31, 2004				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
			(in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net income	$ 35,729	$ 44,464	$ 30,773	$ (75,237)	$ 35,729
Adjustments to reconcile net income to net cash provided by operating activities:					
Equity earnings	(44,464)	(30,773)	—	75,237	—
Distributions from subsidiaries	56,518	47,519	—	(104,037)	—
Depreciation, amortization and other	336	11,086	18,048	—	29,470
Net changes in operating assets and liabilities	760	(9,271)	(6,439)	6,977	(7,973)
NET CASH PROVIDED BY OPERATING ACTIVITIES	48,879	63,025	42,382	(97,060)	57,226
CASH FLOWS FROM INVESTING ACTIVITIES					
Acquisitions	—	—	(138,701)	—	(138,701)
Additions to property, equipment and other	—	(10,600)	(6,651)	—	(17,251)
Intercompany	(369,533)	(97,602)	—	467,135	—
NET CASH USED IN INVESTING ACTIVITIES	(369,533)	(108,202)	(145,352)	467,135	(155,952)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	322,621	55,316	105,767	(371,294)	112,410
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	1,967	8,920	2,797	—	13,684
CASH AND CASH EQUIVALENTS, beginning of year	746	8,603	350	—	9,699
CASH AND CASH EQUIVALENTS, end of year	$ 2,713	$ 17,523	$ 3,147	$ —	$ 23,383

	Statement of Cash Flows Year Ended December 31, 2003				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands)				
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net income	$ 25,029	$ 25,010	$ 27,907	$ (52,917)	$ 25,029
Adjustments to reconcile net income to net cash provided by operating activities:					
Equity earnings	(25,010)	(27,907)	—	52,917	—
Distributions from subsidiaries	42,115	39,613	—	(81,728)	—
Depreciation, amortization and other	—	12,514	12,529	—	25,043
Net changes in operating assets and liabilities	42	(47)	(8,102)	758	(7,349)
NET CASH PROVIDED BY OPERATING ACTIVITIES	42,176	49,183	32,334	(80,970)	42,723
CASH FLOWS FROM INVESTING ACTIVITIES					
Acquisitions	—	—	(169,740)	—	(169,740)
Additions to property, equipment and other	—	(6,752)	(3,840)	—	(10,592)
Intercompany	(90,000)	(167,000)	—	257,000	—
NET CASH USED IN INVESTING ACTIVITIES	(90,000)	(173,752)	(173,580)	257,000	(180,332)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	46,207	120,921	133,402	(177,095)	123,435
NET DECREASE IN CASH AND CASH EQUIVALENTS	(1,648)	(4,682)	(7,844)	—	(14,174)
CASH AND CASH EQUIVALENTS, beginning of year	2,394	13,285	8,194	—	23,873
CASH AND CASH EQUIVALENTS, end of year	$ 746	$ 8,603	$ 350	$ —	$ 9,699

22. QUARTERLY FINANCIAL DATA (unaudited)

	Year ended December 31, 2005				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(in thousands, except per unit amounts)				
Net revenue	$ 49,247	$ 52,775	$ 54,520	$ 67,760	$ 224,302
Operating income	9,227	17,667	19,342	20,176	66,412
Net income	3,421	12,220	12,166	11,841	39,648
Basic net income per limited partner unit	0.17	0.40	0.39	0.30	1.25
Diluted net income per limited partner unit	0.17	0.40	0.39	0.30	1.25

	Year ended December 31, 2004				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(in thousands, except per unit amounts)				
Net revenue	$ 39,662	$ 45,997	$ 48,091	$ 47,649	$ 181,399
Operating income	12,042	16,172	15,126	13,728	57,068
Net income	8,077	9,128	9,890	8,634	35,729
Basic net income per limited partner unit	0.32	0.30	0.33	0.29	1.23
Diluted net income per limited partner unit	0.31	0.30	0.33	0.29	1.23

QuickLinks

PACIFIC ENERGY PARTNERS, L.P. AND SUBSIDIARIES CONSOLIDATED BALANCE SHEETS December 31, 2005 and 2004
PACIFIC ENERGY PARTNERS, L. P. AND SUBSIDIARIES CONSOLIDATED STATEMENTS OF INCOME Years ended December 31, 2005, 2004 and 2003
PACIFIC ENERGY PARTNERS, L.P. AND SUBSIDIARIES CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL Years ended December 31, 2005, 2004 and 2003 (in thousands)
PACIFIC ENERGY PARTNERS, L.P. AND SUBSIDIARIES CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME Years ended December 31, 2005, 2004 and 2003
PACIFIC ENERGY PARTNERS, L.P. AND SUBSIDIARIES CONSOLIDATED STATEMENTS OF CASH FLOWS Years ended December 31, 2005, 2004 and 2003
PACIFIC ENERGY PARTNERS, L.P. AND SUBSIDIARIES NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Exhibit 99.3

Plains All American Pipeline, L.P.

Unaudited Pro Forma Condensed Combined Financial Statements of Plains All American Pipeline, L.P. as of and for the three months ended March 31, 2006 and for the year ended December 31, 2005.

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PLAINS ALL AMERICAN PIPELINE, L.P.
UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL STATEMENTS

The following unaudited pro forma condensed combined financial statements give effect to the merger of Pacific Energy Partners, L.P. ("Pacific") into Plains All American Pipeline, L.P. ("Plains"). The merger-related transactions include:

- The acquisition from LB Pacific, LP and its affiliates ("LB Pacific") of the general partner interest and incentive distribution rights of Pacific as well as 2,616,250 common units of Pacific and 7,848,750 subordinated units of Pacific for a total of $700 million in cash; and

- The acquisition of the balance of Pacific's equity through a tax-free unit-for-unit merger in which each Pacific unitholder (other than LB Pacific) will receive 0.77 newly issued Plains common units for each Pacific common unit.

Upon consummation of the merger-related transactions, the general partner and limited partner ownership interests in Pacific will be extinguished and Pacific will be merged with and into Plains. Pacific's operating subsidiaries will be directly or indirectly owned by Plains. The proposed merger-related transactions will be accounted for using the purchase method of accounting. The estimates of fair value of the assets acquired and liabilities assumed are based on preliminary assumptions, pending the completion of an independent appraisal, with any excess of purchase price over the net fair value of assets acquired and liabilities assumed assigned to goodwill.

The following unaudited pro forma condensed statements of combined operations for the three months ended March 31, 2006 and the year ended December 31, 2005 have been prepared as if the transactions described above had taken place on January 1, 2005. The unaudited pro forma condensed combined balance sheet at March 31, 2006 assumes the transactions were consummated on that date.

The unaudited pro forma financial statements should be read in conjunction with and are qualified in their entirety by reference to the notes accompanying such unaudited pro forma financial statements as well as the notes included in the historical financial statements included in the following public filings:

(1) Plains' Annual Report on Form 10-K for the year ended December 31, 2005;

(2) Plains' Quarterly Report on Form 10-Q for the three months ended March 31, 2006;

(3) Pacific's Annual Report on Form 10-K and Form 10-K/A for the year ended December 31, 2005; and

(4) Pacific's Quarterly Report on Form 10-Q for the three months ended March 31, 2006.

The unaudited pro forma financial statements are based on assumptions that Plains believes are reasonable under the circumstances and are intended for informational purposes only. They are not necessarily indicative of the results of the actual or future operations or financial condition that would have been achieved had the transactions occurred at the dates assumed (as noted above).

The unaudited pro forma financial statements do not give effect to any divestiture of assets that may be required for governmental clearance of the proposed merger or to any anticipated cost savings or other financial benefits expected to result from the merger.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
UNAUDITED PRO FORMA CONDENSED COMBINED BALANCE SHEET
March 31, 2006
(in millions)

	Plains Historical	Pacific Historical	Pro Forma Adjustments	Plains Pro Forma
CURRENT ASSETS				
Cash and cash equivalents	$ 9.3	$ 11.9	$ 20.4 (b) 902.0 (b) (181.7)(b) (740.7)(b)	$ 21.2
Trade accounts receivable and other receivables, net	1,242.8	148.2	(8.1)(c)	1,382.9
Inventory	1,027.4	36.4	1.9 (b)	1,065.7
Other current assets	94.9	9.7	—	104.6
Total current assets	2,374.4	206.2	(6.2)	2,574.4
PROPERTY AND EQUIPMENT, net	1,899.5	1,205.6	(37.3)(a) 235.7 (b)	3,303.5
OTHER ASSETS				
Pipeline linefill in owned assets	180.1	—	36.5 (a) 16.5 (b)	233.1
Inventory in third party assets	71.9	—	0.8 (a) 1.5 (b)	74.2
Investments in unconsolidated affiliates	113.3	8.1	—	121.4
Goodwill	47.4	—	800.4 (b)	847.8
Other, net	47.1	86.4	28.3 (b)	161.8
Total assets	$ 4,733.7	$ 1,506.3	$ 1,076.2	$ 7,316.2
CURRENT LIABILITIES				
Accounts payable and accrued liabilities	$ 1,265.1	$ 149.4	$ (8.1)(c)	$ 1,406.4
Due to related parties	6.9	—	—	6.9
Short-term debt	875.8	—	—	875.8
Other current liabilities	146.3	11.6	—	157.9
Total current liabilities	2,294.1	161.0	(8.1)	2,447.0
LONG-TERM LIABILITIES				
Long-term debt under credit facilities and other	4.4	—	181.7 (a) 902.0 (b) (181.7)(b)	906.4
Senior notes, net	947.1	—	419.3 (a) 21.7 (b)	1,388.1
Senior notes and credit facilities, net	—	601.0	(601.0)(a)	—
Other long-term liabilities and deferred credits	49.4	56.1	7.9 (b)	113.4
Total liabilities	3,295.0	818.1	741.8	4,854.9
COMMITMENTS AND CONTINGENCIES				
PARTNERS' CAPITAL				
Common unitholders	1,400.0	636.7	1,002.2 (b) (636.7)(b)	2,402.2
Subordinated unitholders	—	22.8	(22.8)(b)	—
General partner	38.7	12.3	20.4 (b) (12.3)(b)	59.1
Accumulated other comprehensive income	—	16.4	(16.4)(b)	—
Total partners' capital	1,438.7	688.2	334.4	2,461.3
Total Liabilities and Partners' Capital	$ 4,733.7	$ 1,506.3	$ 1,076.2	$ 7,316.2

See notes to unaudited pro forma condensed combined financial statements

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
UNAUDITED PRO FORMA CONDENSED STATEMENT OF COMBINED OPERATIONS
For the Three Months Ended March 31, 2006
(in millions, except per unit data)

	Plains Historical	Pacific Historical	Pro Forma Adjustments	Plains Pro Forma
REVENUES	$ 8,635.4	$ 70.5	$ (8.5)(d)	$ 8,697.4
COSTS AND EXPENSES				
Purchases and related costs	8,427.4	—	(8.0)(d)	8,419.4
Field operating costs	82.3	33.4	(0.5)(d)	115.2
General and administrative expenses	31.8	6.9	—	38.7
Depreciation and amortization	21.6	10.0	0.6 (a) (10.0)(e) 11.0 (f)	33.2
Total costs and expenses	8,563.1	50.3	(6.9)	8,606.5
Share of net income of Frontier	—	0.4	(0.4)(a)	—
OPERATING INCOME	72.3	20.6	(2.0)	90.9
OTHER INCOME (EXPENSE)				
Equity earnings (loss) in unconsolidated affiliates	(0.2)	—	0.4 (a)	0.2
Interest expense	(15.3)	(9.1)	(10.0)(g) 0.6 (a)	(33.8)
Interest income and other, net	0.3	0.4	—	0.7
Income from continuing operations before income taxes	57.1	11.9	(11.0)	58.0
Income tax (expense) benefit:				
Current	—	(0.4)	— (h)	(0.4)
Deferred	—	0.1	— (h)	0.1
Income from continuing operations before cumulative effect of change in accounting principle	57.1	11.6	(11.0)	57.7
Cumulative effect of change in accounting principle	6.3	—	—	6.3
NET INCOME (LOSS) FROM CONTINUING OPERATIONS	$ 63.4	$ 11.6	$ (11.0)	$ 64.0
NET INCOME FROM CONTINUING OPERATIONS—LIMITED PARTNERS	$ 56.7			$ 62.1
NET INCOME FROM CONTINUING OPERATIONS—GENERAL PARTNER	$ 6.7			$ 1.9
BASIC NET INCOME FROM CONTINUING OPERATIONS PER LIMITED PARTNER UNIT				
Basic net income per limited partner unit before cumulative effect of change in accounting principle	$ 0.65			$ 0.55
Cumulative effect of change in accounting principle per limited partner unit	0.08			0.06
Basic net income from continuing operations per limited partner unit	$ 0.73			$ 0.61
DILUTED NET INCOME FROM CONTINUING OPERATIONS PER LIMITED PARTNER UNIT				
Diluted net income per limited partner unit before cumulative effect of change in accounting principle	$ 0.63			$ 0.54
Cumulative effect of change in accounting principle per limited partner unit	0.08			0.06
Diluted net income from continuing operations per limited partner unit	$ 0.71			$ 0.60
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	74.0		22.3 (b)	96.3
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	75.7		22.3 (b)	98.0

See notes to unaudited pro forma condensed combined financial statements

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
UNAUDITED PRO FORMA CONDENSED STATEMENT OF COMBINED OPERATIONS
For the Twelve Months Ended December 31, 2005
(in millions, except per unit data)

	Plains Historical	Pacific Historical	Pro Forma Adjustments	Plains Pro Forma
REVENUES	$ 31,177.3	$ 224.3	$ (12.6)(d)	$ 31,389.0
COSTS AND EXPENSES				
Purchases and related costs	30,442.5	—	(11.2)(d)	30,431.3
Field operating costs	272.5	104.4	(1.4)(d)	375.5
General and administrative expenses	103.2	18.5	—	121.7
Accelerated long-term incentive plan compensation expense	—	3.1	—	3.1
Line 63 oil release costs	—	2.0	—	2.0
Transaction costs	—	1.8	—	1.8
Depreciation and amortization	83.5	29.4	2.0 (a) (29.4)(e) 43.9 (f)	129.4
Total costs and expenses	30,901.7	159.2	3.9	31,064.8
Other, net	—	(0.5)	—	(0.5)
Share of net income of Frontier	—	1.8	(1.8)(a)	—
OPERATING INCOME	275.6	66.4	(18.3)	323.7
OTHER INCOME (EXPENSE)				
Equity earnings in unconsolidated affiliates	1.0	—	1.8 (a)	2.8
Interest expense	(59.4)	(26.7)	(40.6)(g) 2.0 (a)	(124.7)
Interest income and other, net	0.6	1.1	—	1.7
Income from continuing operations before income taxes	217.8	40.8	(55.1)	203.5
Income tax (expense) benefit:				
Current	—	(1.3)	— (h)	(1.3)
Deferred	—	0.1	— (h)	0.1
NET INCOME (LOSS) FROM CONTINUING OPERATIONS	$ 217.8	$ 39.6	$ (55.1)	$ 202.3
NET INCOME FROM CONTINUING OPERATIONS—LIMITED PARTNERS	$ 198.8			$ 198.3
NET INCOME FROM CONTINUING OPERATIONS—GENERAL PARTNER	$ 19.0			$ 4.0
BASIC NET INCOME FROM CONTINUING OPERATIONS PER LIMITED PARTNER UNIT	$ 2.77			$ 2.10
DILUTED NET INCOME FROM CONTINUING OPERATIONS PER LIMITED PARTNER UNIT	$ 2.72			$ 2.07
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	69.3		22.3 (b)	91.6
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	70.5		22.3 (b)	92.8

See notes to unaudited pro forma condensed combined financial statements

These unaudited pro forma condensed combined financial statements and underlying pro forma adjustments are based upon currently available information and certain estimates and assumptions made by the management of Plains and Pacific; therefore, actual results could differ materially from the pro forma information. However, we believe the assumptions provide a reasonable basis for presenting the significant effects of the transactions noted herein. Plains believes the pro forma adjustments give appropriate effect to those assumptions and are properly applied in the pro forma information. Please read "Pro Forma Sensitivity Analysis" for assumptions related to fair value estimates.

The Plains Pro Forma income before cumulative effect of change in accounting principle for the year ended December 31, 2005 includes, as required, the following pro forma adjustments related to the acquisition of the Valero assets that Pacific acquired effective September 30, 2005: (i) depreciation expense for the entire year of approximately $11 million associated with Plains' estimated purchase price allocated to the Valero assets; and (ii) interest expense of approximately $11 million for the entire year on the $175 million 6$^{1}/_{4}$% senior notes issued to fund the asset acquisition. However, since the Valero transaction was an asset acquisition, the Plains Pro Forma income before cumulative effect of change in accounting principle for the year ended December 31, 2005 does not include revenues and related operating expenses for the period prior to the asset acquisition by Pacific. In addition, the Plains Pro Forma income before cumulative effect of change in accounting principle for the year ended December 31, 2005 and the three months ended March 31, 2006 does not include any synergies that Plains expects to achieve as a result of the merger with Pacific.

The merger of Pacific into Plains presented in these pro forma statements has been accounted for using the purchase method of accounting and the purchase price allocation has been estimated in accordance with Statement of Financial Accounting Standards No. 141, "Business Combinations." The total estimated consideration is summarized below (in millions):

Cash payment to LB Pacific	$	700.0
Estimated fair value of Plains common units to be issued in exchange for Pacific common units (see below)		1,002.2
Assumption of Pacific debt (at estimated fair value)		622.7
Estimated transaction costs		40.7
Total consideration	$	2,365.6

Plains will exchange 0.77 of its common units for each Pacific common unit remaining after Plains' purchase of 2,616,250 common units owned by LB Pacific. Although cash will be paid for any fractional units as a result of the exchange, such amount is not estimable at this time. Plains currently estimates that the number of Plains common units to be issued in the exchange will be 22,262,030 calculated as follows:

Pacific units outstanding at March 31, 2006		
Common units		31,457,782
Subordinated units		7,848,750
Total historical units outstanding at March 31, 2006		39,306,532
Pro forma adjustments to Pacific historical units outstanding:		
Plains purchase of subordinated units held by LB Pacific		(7,848,750)
Plains purchase of common units held by LB Pacific		(2,616,250)
Issuance of common units for outstanding Pacific restricted unit awards		70,195
Pro forma Pacific common units subject to exchange offer by Plains		28,911,727
Exchange ratio (0.77 Plains common units for each Pacific common unit)		0.77
Pro forma Plains units to be issued to Pacific common unitholders in connection with merger		22,262,030
Average closing price of Plains common units (see below)	$	45.02
Estimated fair value of Plains common units to be issued in exchange for Pacific common units (in millions)	$	1,002.2

In accordance with purchase accounting rules, the pro forma value of the units issued in the exchange is based on the average closing price of Plains common units immediately prior to and after the merger was announced on June 12, 2006. The following table shows the closing prices of Plains common units for the two trading days prior to and after the proposed merger was announced.

June 8, 2006	$	46.30
June 9, 2006		46.10
June 13, 2006		43.88
June 14, 2006		43.81
Average closing price of Plains common units	$	45.02

Upon completion of the proposed merger or shortly thereafter, Plains will obtain a third-party valuation of Pacific's assets and liabilities in order to develop a definitive allocation of the purchase price. As a result, the final purchase price allocation may result in some amounts being assigned to tangible or amortizable intangible assets apart from goodwill.

The following table shows Plains' preliminary purchase price allocation (in millions):

Description	Amount	Average Depreciable Life
PP&E	$ 1,404.0	5-40
Inventory	38.3	n/a
Pipeline linefill and inventory in third party assets	55.3	n/a
Intangible assets	96.8	30
Working capital, excluding inventory	8.8	n/a
Other long-term assets and liabilities, net	(38.0)	n/a
Goodwill (see below)	800.4	n/a
Total	$ 2,365.6	

To the extent that any amount is assigned to a tangible or finite lived intangible asset, this amount may ultimately be depreciated or amortized (as appropriate) to earnings over the expected period of benefit of the asset. To the extent that any amount remains as goodwill or indefinite lived intangible assets, this amount would not be subject to depreciation or amortization, but would be subject to periodic impairment testing and, if necessary, would be written down to fair value should circumstances warrant.

The following table shows Plains' preliminary calculation of the estimated pro forma goodwill amount (in millions):

Cash payment to LB Pacific	$ 700.0
Estimated fair value of Plains common units to be issued in exchange for Pacific public units	1,002.2
Estimated transaction costs	40.7
Total consideration, excluding debt assumed	1,742.9
Estimated fair value of Pacific's net assets	942.5
Excess of purchase price over net assets of Pacific preliminarily assigned to goodwill	$ 800.4

For an analysis of the sensitivity of pro forma earnings to potential reclassifications of this preliminary goodwill amount to tangible or intangible assets, please read "Pro Forma Sensitivity Analysis" below.

The following table shows Plains' preliminary calculation of the sources of funding for the acquisition (in millions):

Estimated fair value of Plains common units to be issued in exchange for Pacific common units	$ 1,002.2
Plains general partner capital contribution	20.4
Assumption of Pacific debt (at estimated fair value)	622.7
Repayment of Pacific credit facility	(181.7)
Plains new debt incurred	902.0
Total sources of funding	$ 2,365.6

Pro Forma Adjustments

a. To reclassify certain line items on Pacific's historical financial statements to conform to Plains' historical presentation.

b. Records the cash paid, equity exchanged, additional obligations assumed and adjustments to fair value of the assets purchased and liabilities assumed in the merger based on the purchase method of accounting.

c. Reflects the elimination of accounts receivable and accounts payable balances between Plains and Pacific.

d. Reflects the elimination of purchases and sales between Plains and Pacific.

e. To reverse historical depreciation and amortization as recorded by Pacific.

f. Reflects depreciation and amortization on the acquired assets based on the straight-line method of depreciation over average useful lives ranging from 5 to 40 years.

g. Reflects the adjustment to interest expense for (i) the increase in long-term debt of $902 million from a "bridge" credit facility using an average interest rate of 5.6%, (ii) the decrease in long-term debt of approximately $182 million from the repayment of the Pacific credit facility and (iii) the amortization of the premium on the senior notes. The impact to interest expense of a 1/8% change in interest rates would be approximately $1.1 million per year.

h. The pro forma adjustments to the statements of combined operations have not been tax-effected as the effect on income tax expense is not deemed to be material to the pro forma results of operations.

Plains Earnings per Limited Partner Unit

Earnings per limited partner unit is determined by dividing net income after deducting the amount allocated to the general partner interest, including its incentive distribution in excess of its 2% interest, by the weighted average number of limited partner units outstanding during the period. Plains' general partner is entitled to receive incentive distributions if the amount it distributes with respect to any quarter exceeds levels specified in its partnership agreement. Upon closing of the proposed merger, Plains' general partner has agreed to reduce the amounts due it as incentive distributions commencing with the earlier to occur of (i) the payment date of the first quarterly distribution declared and paid after the closing date that equals or exceeds $0.80 per unit or (ii) the payment date of the second quarterly distribution declared and paid after the closing date. Such adjustment shall be as follows: (i) $5 million per quarter for the first four quarters, (ii) $3.75 million per quarter for the next eight quarters, (iii) $2.5 million per quarter for the next four quarters, and (iv) $1.25 million per quarter for the final four quarters. The total reduction in incentive distributions will be $65 million.

The following sets forth the computation of basic and diluted earnings per limited partner unit for Plains on a historical and pro forma basis. The net income available to limited partners and the weighted average limited partner units outstanding have been adjusted for instruments considered common unit equivalents.

	Quarter ended March 31, 2006		Year ended December 31, 2005	
	Plains Historical	**Plains Pro Forma**	**Plains Historical**	**Plains Pro Forma**
Numerator for basic and diluted earnings per limited partner unit:				
Net income	$ 63.4	$ 64.0	$ 217.8	$ 202.3
Less: General partner's incentive distribution paid	(5.5)	(5.5)	(15.0)	(15.0)
Incentive distribution reduction	—	5.0	—	15.0
Subtotal	57.9	63.5	202.8	202.3
General partner 2% ownership	(1.2)	(1.4)	(4.1)	(4.0)
Net income available to limited partners	56.7	62.1	198.7	198.3
EITF 03-06 additional general partner's distribution	(2.9)	(3.5)	(7.1)	(6.1)
Net income available to limited partners under EITF 03-06	53.8	58.6	191.6	192.2
Less: Limited partner 98% portion of cumulative effect of change in accounting principle	(6.2)	(6.2)	—	—
Limited partner net income before cumulative effect of change in accounting principle	$ 47.6	$ 52.4	$ 191.6	$ 192.2
Denominator:				
Historical weighted average number of limited partner units outstanding	74.0	74.0	69.3	69.3
Common unit exchange	—	22.3	—	22.3
Denominator for basic earnings per limited partner unit	74.0	96.3	69.3	91.6
Effect of dilutive securities:				
Weighted average LTIP units outstanding	1.7	1.7	1.2	1.2
Denominator for diluted earnings per limited partner unit	75.7	98.0	70.5	92.8
Basic net income per limited partner unit before cumulative effect of change in accounting principle	$ 0.65	$ 0.55	$ 2.77	$ 2.10
Cumulative effect of change in accounting principle per limited partner unit	0.08	0.06	—	—
Basic net income per limited partner unit	$ 0.73	$ 0.61	$ 2.77	$ 2.10
Diluted net income per limited partner unit before cumulative effect of change in accounting principle	$ 0.63	$ 0.54	$ 2.72	$ 2.07
Cumulative effect of change in accounting principle per limited partner unit	0.08	0.06	—	—
Diluted net income per limited partner unit	$ 0.71	$ 0.60	$ 2.72	$ 2.07

PRO FORMA SENSITIVITY ANALYSIS

Certain of the pro forma adjustments incorporate Plains' preliminary estimate of the fair value of businesses that Plains is acquiring. Preliminary estimates are that the excess of the purchase price over the preliminary fair values ("excess cost") may be assigned to non-amortizable other intangible assets or goodwill as opposed to depreciable fixed assets or amortizable intangible assets. Upon completion of the proposed merger or shortly thereafter, Plains will obtain a third party valuation of Pacific's assets and liabilities in order to develop a definitive allocation of the purchase price. As a result, the final purchase price allocation may result in some amounts being assigned to tangible or amortizable intangible assets, and this amount may ultimately be depreciated or amortized (as appropriate) to earnings over the expected benefit period of the asset. To the extent that any amount remains as goodwill or indefinite lived intangible assets, this amount would not be subject to depreciation or amortization, but would be subject to periodic impairment testing and, if necessary, would be written down to a lower fair value should circumstances warrant.

The table below shows the potential increase in pro forma depreciation or amortization expense if certain amounts of the goodwill were ultimately assigned to tangible or amortizable intangible assets. For purposes of calculating this sensitivity, Plains has applied the straight-line method of cost allocation over an estimated useful life of 34 years to various fair values. The decrease in annual basic earnings per unit is predicated on the basic earnings per unit determined using the pro forma income from continuing operations amount. The resulting pro forma adjustments are as follows (in millions, except per unit amounts):

For the Quarter Ended March 31, 2006

Estimated Goodwill	Change in Allocation		Average Depreciable Life of Assets	Decrease in Net Income from Continuing Operations	Decrease in Net Income from Continuing Operations per Limited Partner Unit
$800.4	20%	$ 160.1	34	$ (1.2)	$ (0.01)
$800.4	40%	$ 320.2	34	$ (2.4)	$ (0.02)
$800.4	60%	$ 480.2	34	$ (3.5)	$ (0.03)
$800.4	80%	$ 640.3	34	$ (4.7)	$ (0.04)
$800.4	100%	$ 800.4	34	$ (5.9)	$ (0.05)

For the Year Ended December 31, 2005

Estimated Goodwill	Change in Allocation		Average Depreciable Life of Assets	Decrease in Net Income from Continuing Operations	Decrease in Net Income from Continuing Operations per Limited Partner Unit
$800.4	20%	$ 160.1	34	$ (4.7)	$ (0.04)
$800.4	40%	$ 320.2	34	$ (9.4)	$ (0.08)
$800.4	60%	$ 480.2	34	$ (14.1)	$ (0.12)
$800.4	80%	$ 640.3	34	$ (18.8)	$ (0.16)
$800.4	100%	$ 800.4	34	$ (23.5)	$ (0.19)

QuickLinks

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