PACIFIC ENERGY PARTNERS LP
Form 10-Q
November 14, 2005

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2005

OR

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

For the transition period from to

Commission File Number 1-31345

PACIFIC ENERGY PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

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

5900 Cherry Avenue

Long Beach, CA 90805-4408

(Address of principal executive offices)

(562) 728-2800

(Registrant s telephone number, including area code)

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

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

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

There were 31,448,931 of the registrant s Common Units and 7,848,750 of the registrant s Subordinated Units outstanding at September 30, 2005.

PACIFIC ENERGY PARTNERS, L.P.

FORM 10-Q

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ITEM 1. Financial Statements

PACIFIC ENERGY PARTNERS, L.P. (Note 1)
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2005 (in thousands)	December 31, 2004
ASSETS		
Current assets:		
Cash and cash equivalents	$ 25,775	$ 23,383
Crude oil sales receivable	98,539	28,609
Transportation and storage accounts receivable	19,476	20,137
Canadian goods and services tax receivable	9,177	7,632
Insurance proceeds receivable (note 3)	8,829	
Due from related parties (note 4)	638	
Crude oil inventory	13,919	9,174
Prepaid expenses	7,089	4,159
Other	3,403	2,451
Total current assets	186,845	95,545
Property and equipment, net (note 2)	1,029,619	718,624
Intangible assets (note 2)	217,506	38,026
Investment in Frontier	7,805	7,886
Other assets, net	15,540	9,824
	$ 1,457,315	$ 869,905
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 46,529	$ 14,872
Accrued crude oil purchases	93,013	27,231
Line 63 oil release reserve (note 3)	5,411	
Accrued interest	5,475	1,124
Due to related parties (note 4)		533
Derivatives liability current portion	1,328	400
Other	4,452	3,885
Total current liabilities	156,208	48,045
Senior notes and credit facilities, net (note 5)	539,789	357,163
Deferred income taxes	36,111	34,556
Environmental liabilities	16,125	7,269
Other liabilities	2,331	406
Total liabilities	750,564	447,439
Commitments and contingencies (notes 3 and 10)		
Partners capital:		
Common unitholders (31,448,931 and 19,158,747 units outstanding at September 30, 2005 and December 31, 2004, respectively)	651,582	361,427
Subordinated unitholders (7,848,750 and 10,465,000 units outstanding at September 30, 2005 and December 31, 2004, respectively)	26,462	41,521
General Partner interest	12,710	6,280
Undistributed employee long-term incentive compensation (note 7)		116
Accumulated other comprehensive income	15,997	13,122
Net partners capital	706,751	422,466
	$ 1,457,315	$ 869,905

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. (Note 1)
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	**2004**	**2005**	**2004**
	(in thousands, except per unit amounts)			
Pipeline transportation revenue	$ 27,283	$ 28,160	$ 83,067	$ 79,879
Storage and terminaling revenue	9,731	8,391	30,923	27,773
Pipeline buy/sell transportation revenue	11,683	7,972	28,905	11,662
Crude oil sales, net of purchases of $188,901 and $103,192 for the three months ended September 30, 2005 and 2004 and $425,733 and $278,689 for the nine months ended September 30, 2005 and 2004	5,823	3,568	13,647	14,436
Net revenue	54,520	48,091	156,542	133,750
Expenses:				
Operating	25,019	22,788	72,065	62,572
Line 63 oil release costs (note 3)			2,000	
General and administrative	4,115	3,762	12,987	11,252
Accelerated long-term incentive plan compensation expense (note 7)			3,115	
Transaction costs (notes 4 and 8)			1,807	
Depreciation and amortization	6,560	6,821	19,695	17,776
	35,694	33,371	111,669	91,600
Share of net income of Frontier	516	406	1,363	1,190
Operating income	19,342	15,126	46,236	43,340
Interest expense	(6,237)	(5,234)	(17,679)	(13,743)
Write-off of deferred financing cost and interest rate swap termination expense				(2,901)
Other income	494	219	1,387	606
Income before income taxes	13,599	10,111	29,944	27,302
Income tax expense:				
Current	(1,411)	(118)	(1,898)	(150)
Deferred	(22)	(103)	(239)	(57)
	(1,433)	(221)	(2,137)	(207)
Net income	$ 12,166	$ 9,890	$ 27,807	$ 27,095
Net income (loss) for the general partner interest (note 8)	$ 243	$ 198	$ (1,215)	$ 542
Net income for the limited partner interests	$ 11,923	$ 9,692	$ 29,022	$ 26,553
Basic net income per limited partner unit	$ 0.39	$ 0.33	$ 0.97	$ 0.95
Diluted net income per limited partner unit	$ 0.39	$ 0.33	$ 0.96	$ 0.94
Weighted average limited partner units outstanding:				
Basic	30,761	29,574	30,051	28,008
Diluted	30,762	29,682	30,089	28,125

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. (Note 1)
CONDENSED CONSOLIDATED STATEMENT OF PARTNERS CAPITAL
(Unaudited)

	Limited Partner Units		Limited Partner Amounts		General Partner Interest	Undistributed Employee Long-Term Incentive Compensation	Accumulated Other Comprehensive Income	Total
	Common	Subordinated	Common	Subordinated				
	(in thousands)							
Balance, December 31, 2004	19,159	10,465	$ 361,427	$ 41,521	$ 6,280	$ 116	$ 13,122	$ 422,466
Net income (note 8)			19,741	9,281	(1,215)			27,807
Distribution to partners			(29,341)	(15,959)	(924)			(46,224)
Issuance of common units, net of fees and offering expenses (note 6)	9,533		289,122		6,116			295,238
General partner contribution (note 8)					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 (note 7)	99		1,545		31	(3,002)		(1,426)
Exercise of unit options pursuant to long-term incentive plan	42		707		15			722
Foreign currency translation adjustment							3,377	3,377
Change in fair value of hedging derivatives							(502)	(502)
Conversion of subordinated units to common units	2,616	(2,616)	8,381	(8,381)				
Balance, September 30, 2005	31,449	7,849	$ 651,582	$ 26,462	$ 12,710	$	$ 15,997	$ 706,751

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. (Note 1)
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
	(in thousands)			
Net income	$ 12,166	$ 9,890	$ 27,807	$ 27,095
Change in fair value of hedging derivatives	303	(1,107)	(502)	3,797
Change in foreign currency translation adjustment	5,678	5,313	3,377	7,742
Comprehensive income	$ 18,147	$ 14,096	$ 30,682	$ 38,634

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P. (Note 1)
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30,	
	2005	2004
	(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 27,807	$ 27,095
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	19,695	17,776
Amortization of debt issue costs and debt discount accretion	1,424	1,100
Write-off of deferred financing costs		2,321
Non-cash employee compensation under long-term incentive plan	2,886	1,777
Deferred tax expense	239	57
Share of net income of Frontier	(1,363)	(1,190)
Other non-cash adjustments	58	
Distributions from Frontier, net	1,317	(44)
Net changes in operating assets and liabilities:		
Crude oil sales receivable	(68,206)	(1,704)
Transportation and storage accounts receivable	909	(3,318)
Insurance proceeds receivable	(8,829)	
Other current assets and liabilities	(6,499)	(13,628)
Accounts payable and other accrued liabilities	27,354	11,537
Accrued crude oil purchases	64,917	841
Line 63 oil release reserve	5,411	
Other non-current assets and liabilities	(1,465)	(400)
NET CASH PROVIDED BY OPERATING ACTIVITIES	65,655	42,220
CASH FLOWS FROM INVESTING ACTIVITIES		
Acquisitions	(461,165)	(139,000)
Additions to property and equipment	(27,265)	(11,522)
Other		(621)
NET CASH USED IN INVESTING ACTIVITIES	(488,430)	(151,143)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of common units, net of fees and offering expenses	289,122	125,881
Capital contributions from the general partner	8,569	2,708
Net proceeds from senior notes offering	170,997	241,086
Repayment of term loan		(225,000)
Proceeds from credit facilities	203,291	157,924
Repayment of credit facilities	(195,661)	(145,453)
Deferred financing costs	(4,676)	(1,388)
Distributions to partners	(46,224)	(41,800)
Issuance of common units pursuant to exercise of unit options	707	
Related parties	(1,171)	(206)
NET CASH PROVIDED BY FINANCING ACTIVITIES	424,954	113,752
Effect of translation adjustment on cash	213	
NET INCREASE IN CASH AND CASH EQUIVALENTS	2,392	4,829
CASH AND CASH EQUIVALENTS, beginning of reporting period	23,383	9,699
CASH AND CASH EQUIVALENTS, end of reporting period	$ 25,775	$ 14,528

See accompanying notes to condensed consolidated financial statements.

PACIFIC ENERGY PARTNERS, L.P.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
September 30, 2005
(Unaudited)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

Pacific Energy Partners, L.P. and its subsidiaries (the Partnership), was, during the period of this report, engaged principally in the business of gathering, transporting, storing and distributing crude oil and related products in California and the Rocky Mountain region, which includes Alberta, Canada. The Partnership generated revenue primarily by charging tariff rates for transporting crude oil and related products on its pipelines and by leasing storage capacity. The Partnership also buys and sells crude oil, activities that are complementary to the Partnership s pipeline transportation business. During the period covered by this report, the Partnership operated primarily in California, Colorado, Montana, Wyoming and Utah in the United States, and in Alberta, Canada. On September 30, 2005, the Partnership, through two of its wholly owned subsidiaries, acquired certain refined products and crude oil terminal assets in the San Francisco, California and Philadelphia, Pennsylvania areas, and a refined products pipeline and terminal assets in the U.S. Rocky Mountains. See also Note 2 Acquisitions .

The Partnership conducts its business through two business segments: the West Coast Business Unit and the Rocky Mountain Business Unit.

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 (TAC). On March 3, 2005, TAC 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 4 Related Party Transactions). Pacific Energy GP, LP is managed by its general partner, Pacific Energy Management LLC, a Delaware limited liability company, thus the officers and Board of Directors of PEM manages the business affairs of the Partnership and its General Partner.

The unaudited condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America for interim financial reporting and with Securities and Exchange Commission (SEC) regulations. Accordingly, these statements have been condensed and do not include all of the information and footnotes required for complete financial statements. These statements involve the use of estimates and judgments where appropriate. In the opinion of management, all adjustments, consisting of normal recurring accruals considered necessary for a fair presentation, have been included. The results of operations for the three and nine months ended September 30, 2005 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 Rangeland system, including the Mid-Alberta Pipeline (MAPL), since the acquisition of those assets on May 11, 2004 and June 30, 2004, respectively.

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, 2004. Certain prior year balances in the accompanying condensed consolidated financial statements have been reclassified to conform to the current year presentation.

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.

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

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 outstanding limited partner units to diluted weighted average limited partner units.

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2005	**2004**	**2005**	**2004**
	(in thousands)			
Basic weighted average limited partner units	30,761	29,574	30,051	28,008
Effect of restricted units		93	25	102
Effect of options	1	15	13	15
Diluted weighted average limited partner units	30,762	29,682	30,089	28,125

Allocation of Net Income

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 assumed in connection with its acquisition by LBP and for which neither the Partnership nor the limited partners are responsible (see Note 8 Allocation of Net Income).

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 of transactions in which an entity exchanges its equity instruments for goods or services. SFAS 123R is effective for the Partnership as of the beginning of the first annual reporting period that begins after June 15, 2005. The Partnership has not yet determined the impact of the adoption of SFAS 123R on the Partnership s consolidated financial statements.

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. The Statement is effective for fiscal periods beginning after June 15, 2005. The Partnership does not expect the adoption of SFAS 153 to have a material impact on its 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 is effective for the Partnership no later than the end of fiscal years ending after December 15, 2005. The Partnership is in the process of determining the impact of FIN 47 on its 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.

2. ACQUISITIONS

Acquisition Of Assets From Valero, L.P.

On September 30, 2005, the Partnership completed its purchase of certain terminal and pipeline assets (the Valero Acquisition) from various subsidiaries of Valero, L.P. (the Sellers) for an aggregate purchase price of $455.0 million, plus approximately $12.0 million for the assumption of certain legal, environmental and operating liabilities and $3.4 million for closing costs. 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 terminal and Richmond terminal in the San Francisco, California area, (ii) the North Philadelphia and South Philadelphia terminals and the Paulsboro, New Jersey terminal in the Philadelphia, Pennsylvania area, and (iii) a 550-mile refined products pipeline with four terminals in the U.S. Rocky Mountains.

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, the South Philadelphia and the Paulsboro, New Jersey 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 refined products pipeline system, 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 West Pipeline System has various segments with different receipt and delivery points.

The majority of the West Pipeline System was constructed in 1948, with extensions to Rapid City, South Dakota and Fountain, Colorado, 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. Additional tankage has been constructed and pipeline system and terminal improvements have occurred over the years since their initial startup.

The Partnership intends to fully integrate the operations, maintenance, marketing and business development of the West Pipeline System with its existing pipeline activities in the Rocky Mountain Business Unit. It intends to similarly integrate the San Francisco area terminals 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 intends to develop or acquire software associated with the complex task of volumetric and revenue accounting for the acquired assets, and will use its existing financial accounting software for other accounting functions. In addition, the Partnership is not acquiring the pipeline control center or the software and other operating systems required for the West Pipeline System, and will develop and install new operating systems that will be operated out of its Long Beach pipeline control center. The Seller has 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 have not been operated historically 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 intends to make significant changes to the assets in the future, which may result in significant operating differences and revenues generated. 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.

Prior to closing the acquisition, the Partnership, pursuant to its agreement with the Sellers, made conditional offers of employment to the Sellers employees directly involved in the operation of the acquired assets. The Partnership hired 76 of these employees, including certain field level managerial and supervisory employees, operators, technicians, and engineers/project coordinators. The Partnership intends to hire additional accounting, environmental, engineering, pipeline controllers and technical staff to support the acquired assets.

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

The Valero Acquisition was consummated effective at 11:59 p.m. on September 30, 2005 and no amount was earned and included in the statements of income for the three and nine months ended September 30, 2005. The Partnership has engaged an independent appraiser to complete an appraisal of the fair values of the acquired assets, and is completing its review and determination of the fair values of the assets acquired and liabilities assumed. Accordingly, the allocation of the purchase price is subject to revision. Based upon the preliminary estimates, the purchase price is being allocated to land and related improvements, depreciable pipelines and related equipment, storage tanks and related equipment, truck racks, rights of way, amortizable intangible assets and other properties. The Partnership anticipates depreciating the pipeline and tankage over forty years, other property and equipment over three to twenty years, and amortizable intangible assets over their estimated lives of up to 40 years. The Partnership is also completing its assessment of the $12.0 million of assumed liabilities, and accordingly its initial estimate is subject to revision, including the liability associated with one legal action pending against one of the Sellers that the Partnership agreed to assume (See Note 10 Contingencies).

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 5 Long-term Debt and Note 6 Partner s Capital for further discussion on these financing arrangements).

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.

3. 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 March 2006, the Partnership expects to incur an estimated total of $19.5 million for oil containment and clean-up of the impacted areas, future monitoring costs, potential third-party claims and penalties, and other costs, excluding pipeline repair costs. As of September 30, 2005, the Partnership had incurred approximately $14.1 million of the total expected costs related to the oil release for work performed through that date. Additionally, the Partnership expensed $0.7 million for the repair of Line 63 and expects to incur $1.7 million of Line 63 capital improvements of which $0.8 million has been incurred through September 30, 2005.

The Partnership has a pollution liability insurance policy with a $2.0 million 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 September 30, 2005, the Partnership has recovered $8.7 million from insurance and recorded a receivable of $8.8 million for insurance recoveries it deems probable.

The Partnership recorded $2.0 million in net costs in Line 63 oil release costs in the accompanying condensed consolidated financial statements for the nine months ended September 30, 2005. The $2.0 million net oil release costs consist of the $19.5 million of accrued costs relating to the release, net of insurance recovery of $8.7 million and accrued insurance receipts of $8.8 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. As new information becomes available in future periods, the Partnership may change its provision and recovery estimates.

4. RELATED PARTY TRANSACTIONS

Lehman Brothers, Inc.

In connection with the purchase and the associated financing of the Valero Acquisition including the private equity offering, public equity offering, debt 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. is 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 three and nine months ended September 30, 2005, the Partnership incurred $9.8 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.

Sale of The Anschutz Corporation s Interest in the Partnership

On March 3, 2005, TAC 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 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.

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 severance portion of this payment was recorded as an expense in Transaction costs in the accompanying condensed consolidated income statements (see Note 8 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 will receive 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 TAC: LBP and TAC 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 5 Long-Term Debt , below) and $0.3 million for legal and other expenses (also see Note 8 Allocation of Net Income).

Other Related Party Transactions

Revenue from Related Parties: Rocky Mountain Pipeline System LLC (RMPS), a subsidiary of the Partnership, receives an operating fee and a management fee from Frontier Pipeline Company (Frontier) in connection with time spent by RMPS management and for other services related to Frontier s pipeline s activities. The Partnership owns a 22.2% interest in Frontier, which is not consolidated in the Partnership s financial statements. RMPS received $0.2 million and $0.3 million for each of the three months ended September 30, 2005 and 2004 and $0.6 million and $0.5 million for each of the nine months ended September 30, 2005 and 2004, respectively.

Due from (to) Related Parties: Due from related parties, which includes payroll related items, consists of $0.6 million due from PEM and $0.5 million due to Pacific Energy GP, LP at September 30, 2005 and December 31, 2004, respectively.

5. LONG-TERM DEBT

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

	September 30, 2005		December 31, 2004	
	(in thousands)			
$400 million senior secured revolving credit facility, bearing interest at 6.3% on September 30, 2005, due September 30, 2010	$	114,160	$	
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 $3,965 and $4,202 and including fair value increases of $1,445 and $2,693, respectively		247,480		248,491
6 1⁄4% senior notes, due September 2015, net of unamortized discount of $797		174,203		
Future payment for MAPL assets, net of unamortized discount of $360 and $480, respectively, due June 2007		3,946		3,667
Long-term debt	$	539,789	$	357,163

$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, and 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 will incur 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 September 30, 2005, the Partnership was in compliance with all such covenants.

As of September 30, 2005, $114.2 million was outstanding under the New Credit Facility, including $19.2 million under the Canadian sub-facility, and there was $152.6 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 4 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, including 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 September 30, 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 7⅛% 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 in the accompanying condensed consolidated balance sheet at September 30, 2005 and will be amortized over the remaining life of the 7⅛% 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 TAC reimbursed the Partnership for the entire cost of the Consent Solicitation, which reimbursement is recorded as a partner s capital contribution (see Note 4 Related Party Transactions).

6¼% 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 6¼% 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. 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 7⅛% 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 September 30, 2005, the Partnership was in compliance with all such covenants.

Net proceeds from the issuance of the notes were $171.0 million after deducting the $0.8 million discount and offering expenses of $3.2 million. The net proceeds were used to partially fund the Valero Acquisition.

Additionally, the Partnership entered into a registration rights agreement whereby the Partnership agreed, among other things, to file a registration statement with the SEC within 90 days after the issue date of the notes that will enable holders of the notes to exchange the privately placed notes for publicly registered notes with substantially identical terms, and to file a shelf registration statement for the resale of the notes in certain circumstances. If the Partnership does not comply with its obligations under the registration rights agreement, the interest rate of the notes will increase.

6. PARTNERS CAPITAL

Public Equity Offering

On September 14, 2005, the Partnership sold 4,550,000 common units in an underwritten public offering at a price of $32.00 per unit. On September 16, 2005, the underwriters exercised their over-allotment option and purchased an additional 682,500 common units at the same price. Net proceeds from the offering and exercise of the underwriters option, including the General Partner s contribution of $3.4 million, totaled approximately $163.4 million after deducting underwriting fees and offering expenses of $7.4 million. The Partnership used net proceeds from the equity offering to partially fund the Valero Acquisition.

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 together with the General Partner s contribution of $2.7 million, which were used to partially fund the Valero Acquisition. The Partnership also entered into a Registration Rights Agreement with the institutional investors, whereby the Partnership agreed to file a shelf registration statement with the SEC for the resale from time to time of the privately placed common units, such filing to be made within 90 days after the closing, and for the Partnership thereafter to use commercially reasonable efforts to cause the shelf registration statement to become or be declared effective by the SEC within 180 days after the closing date.

Conversion of Subordinated Units

On August 12, 2005, 2,616,250 of the Partnership s subordinated units were converted to common units pursuant to terms of the Partnership s partnership agreement.

7. VESTING OF UNIT GRANTS UNDER LONG-TERM INCENTIVE PLAN

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.

8. ALLOCATION OF NET INCOME

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
	(in thousands)			
Net income	$ 12,166	$ 9,890	$ 27,807	$ 27,095
Transaction costs reimbursed by general partner:				
7⅛% 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	12,166	9,890	29,614	27,095
General partner s share of income	2 %	2 %	2 %	2 %
General partner allocated share of net income before transaction costs	243	198	592	542
Transaction costs reimbursed by general partner			(1,807)	
Net income (loss) allocated to general partner	$ 243	$ 198	$ (1,215)	$ 542
Income before transaction costs reimbursed by general partner	$ 12,166	$ 9,890	$ 29,614	$ 27,095
Limited partners share of income	98 %	98 %	98 %	98 %
Limited partners share of net income	$ 11,923	$ 9,692	$ 29,022	$ 26,533
Net income (loss) allocated to general partner	$ 243	$ 198	$ (1,215)	$ 542
Net income allocated to limited partners	11,923	9,692	29,022	26,553
Net income	$ 12,166	$ 9,890	$ 27,807	$ 27,095

LBP and TAC 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 4 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 $0.6 million was expensed in the three month period ended March 31, 2005.

9. 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 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 West Pipeline System, which was acquired in the Valero Acquisition,

(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 (for the period since May 11, 2004). Balance sheet information noted below includes the assets acquired in the Valero Acquisition, which closed on September 30, 2005. There was no income contribution for the three or nine months ended September 30, 2005 from the Valero Acquisition. 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 September 30, 2005				
Business unit revenue:				
Pipeline transportation revenue	$ 13,887	$ 14,887	$ (1,491)	$ 27,283
Storage and distribution revenue	9,731			9,731
Pipeline buy/sell transportation revenue(1)		11,683		11,683
Crude oil sales, net of purchases(2)	5,690	163	(30)	5,823
Net revenue	29,308	26,733		54,520
Expenses:				
Operating	16,004	10,536	(1,521)	25,019
Depreciation and amortization	3,491	3,069		6,560
Total expenses	19,495	13,605		31,579
Share of net income of Frontier		516		516
Operating income from segments(4)	$ 9,813	$ 13,644		$ 23,457
Business unit assets(5)	$ 855,191	$ 551,279		$ 1,406,470
Capital expenditures(6)	$ 5,106	$ 9,403		$ 14,509
Three months ended September 30, 2004				
Business unit revenue:				
Pipeline transportation revenue	$ 16,985	$ 12,500	$ (1,325)	$ 28,160
Storage and distribution revenue	8,544		(153)	8,391
Pipeline buy/sell transportation revenue(1)		7,972		7,972
Crude oil sales, net of purchases(2)	3,568			3,568
Net revenue	29,097	20,472		48,091
Expenses:				
Operating	14,309	9,957	(1,478)	22,788
Depreciation and amortization	3,433	3,388		6,821
Total expenses	17,742	13,345		29,609
Share of net income of Frontier		406		406
Operating income from segments(4)	$ 11,355	$ 7,533		$ 18,888
Business unit assets(5)	$ 507,459	$ 330,830		$ 838,289
Capital expenditures(6)	$ 1,054	$ 1,764		$ 2,818

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	West Coast Business Unit	Rocky Mountain Business Unit	Intersegment and Intrasegment Eliminations	Total
	(in thousands)			
Nine months ended September 30, 2005				
Business unit revenue:				
Pipeline transportation revenue	$ 46,525	$ 41,348	$ (4,806)	$ 83,067
Storage and distribution revenue	31,073		(150)	30,923
Pipeline buy/sell transportation revenue(1)		28,905		28,905
Crude oil sales, net of purchases(2)	13,368	369	(90)	13,647
Net revenue	90,966	70,622		156,542
Expenses:				
Operating	46,507	30,604	(5,046)	72,065
Line 63 oil release costs(3)	2,000			2,000
Depreciation and amortization	10,497	9,198		19,695
Total expenses	59,004	39,802		93,760
Share of net income of Frontier		1,363		1,363
Operating income from segments(4)	$ 31,962	$ 32,183		$ 64,145
Business unit assets(5)	$ 855,191	$ 551,279		$ 1,406,470
Capital expenditures(6)	$ 6,790	$ 14,870		$ 21,660
Nine months ended September 30, 2004				
Business unit revenue:				
Pipeline transportation revenue	$ 49,170	$ 34,847	$ (4,138)	$ 79,879
Storage and distribution revenue	28,126		(353)	27,773
Pipeline buy/sell transportation revenue(1)		11,662		11,662
Crude oil sales, net of purchases(2)	14,436			14,436
Net revenue	91,732	46,509		133,750
Expenses:				
Operating	43,197	23,866	(4,491)	62,572
Depreciation and amortization	10,833	6,943		17,776
Total expenses	54,030	30,809		80,348
Share of net income of Frontier		1,190		1,190
Operating income from segments(4)	$ 37,702	$ 16,890		$ 54,592
Business unit assets(5)	$ 507,459	$ 330,830		$ 838,289
Capital expenditures(6)	$ 2,590	$ 6,243		$ 8,833

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(1) Includes the revenue of the Rangeland system, which was acquired on May 11, 2004 and June 30, 2004. Pipeline buy/sell transportation revenue reflects net revenues of approximately $2.5 million on gross revenues for buy/sell transactions of $77.5 million with different parties for the three months ended September 30, 2005 and net revenues of approximately $4.6 million on gross revenues for buy/sell transactions of $126.0 million for the nine months ended September 30, 2005. The remaining amount reflects net revenues on buy/sell transactions with the same party.

(2) The above amounts are net of purchases of $188,901 and $103,192 for the three months ended September 30, 2005 and 2004 and $425,733 and $278,689 for the nine months ended September 30, 2005 and 2004, respectively.

(3) See Note 3 Line 63 Oil Release Reserve for further information.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
	(in thousands)			
Income Statement Reconciliation				
Operating income from above:				
West Coast Business Unit	$ 9,813	$ 11,355	$ 31,962	$ 37,702
Rocky Mountain Business Unit	13,644	7,533	32,183	16,890
Operating income from segments	23,457	18,888	64,145	54,592
Less: General and administrative expense	4,115	3,762	12,987	11,252
Less: Accelerated long-term incentive plan compensation expense			3,115	
Less: Transaction costs			1,807	
Operating income	19,342	15,126	46,236	43,340
Interest expense	(6,237)	(5,234)	(17,679)	(13,743)
Write-off of deferred financing cost and interest rate swap termination expense				(2,901)
Other income	494	219	1,387	606
Income before income taxes	13,599	10,111	29,944	27,302
Income tax expense	(1,433)	(221)	(2,137)	(207)
Net income	$ 12,166	$ 9,890	$ 27,807	$ 27,095

(5) Business unit assets do not include assets related to the Partnership s parent level activities. As of September 30, 2005 and 2004, parent level related assets were $50,845 and $29,651 respectively.

(6) 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 $2,878 and $808 for the three months ended September 30, 2005 and 2004 and $5,605 and $2,689 for the nine months ended September 30, 2005 and 2004, respectively.

10. 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 from a pipeline owned and operated by RPC. The claim seeks Cdn$1 million in general damages, Cdn$2 million 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.

In connection with the Valero Acquisition, we have assumed defense of Support Terminals Services, Inc. (ST Services) in a lawsuit filed in New Jersey state court in 2003 by ExxonMobil Corporation (ExxonMobil). We have also assumed any liability that might be imposed on ST Services as a result of the suit. In the suit, ExxonMobil seeks $400,000 for remediation costs it has paid, 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 on the same defendants. These costs are associated with the Paulsboro, New Jersey terminal that was acquired by us. ExxonMobil claims that the costs are related to releases at the site subsequent to its sale of the terminal to GATX in 1990 and that any remaining remediation requirements are the responsibility of GATX Corporation, Kinder Morgan, and ST Services.

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 3 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.

11. SUBSEQUENT EVENTS

On October 21, 2005, the Partnership declared a cash distribution of $0.5125 per limited partner unit, payable on November 14, 2005, to unitholders of record as of October 31, 2005.

12. SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

Certain of the Partnership s 100% owned subsidiaries have issued unconditional guarantees of the 7 1⁄8% senior notes due 2014 and the 6 1⁄4% senior notes due 2015 (the Senior Notes). These guarantees are full, unconditional, and joint and several. 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. 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, the guarantors of the Senior Notes, are collectively referred to as the Guarantor Subsidiaries, and 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. are referred to as Non-Guarantor Subsidiaries.

The following supplemental condensed consolidating financial information reflects the Parent s separate accounts, the combined accounts of the Guarantor Subsidiaries, the combined accounts of the Parent s 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 September 30, 2005				
	Parent	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Total**
	(in thousands)				
Assets:					
Current assets	$ 150,140	$ 154,017	$ 120,395	$ (237,707)	$ 186,845
Property and equipment		429,949	599,670		1,029,619
Equity investments	409,373	221,461		(623,029)	7,805
Intercompany notes receivable	658,313	341,171		(999,484)	
Intangible assets		179,227	38,279		217,506
Other assets	15,540				15,540
Total assets	$ 1,233,366	$ 1,325,825	$ 758,344	$ (1,860,220)	$ 1,457,315
Liabilities and partners capital:					
Current liabilities	$ 9,932	$ 247,362	$ 136,621	$ (237,707)	$ 156,208
Long-term debt	516,683		23,106		539,789
Deferred income taxes		873	35,238		36,111
Intercompany notes payable		658,313	341,171	(999,484)	
Other liabilities		9,904	8,552		18,456
Total partners capital	706,751	409,373	213,656	(623,029)	706,751
Total liabilities and partners capital	$ 1,233,366	$ 1,325,825	$ 758,344	$ (1,860,220)	$ 1,457,315

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	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
Intercompany notes receivable	283,550	338,884		(622,434)	
Other assets	7,223	1,993	38,634		47,850
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 Three Months Ended September 30, 2005				
	Parent	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Total**
	(in thousands)				
Net operating revenues	$	$ 20,740	$ 35,301	$ (1,521)	$ 54,520
Operating expenses		(11,171)	(15,369)	1,521	(25,019)
General and administrative expense(1)		(3,594)	(521)		(4,115)
Depreciation and amortization expense		(1,633)	(4,927)		(6,560)
Share of net income of Frontier		516			516
Operating income		4,858	14,484		19,342
Interest expense	(4,630)	(818)	(789)		(6,237)
Intercompany interest income (expense)		6,639	(6,639)		
Equity earnings	16,585	6,115		(22,700)	
Other income	211	180	103		494
Income tax expense		(398)	(1,035)		(1,433)
Net income	$ 12,166	$ 16,576	$ 6,124	$ (22,700)	$ 12,166

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

	Statement of Income Three Months Ended September 30, 2004				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating adjustments	Total
	(in thousands)				
Net operating revenues	$	$ 16,068	$ 33,501	$ (1,478)	$ 48,091
Operating expenses		(10,190)	(14,076)	1,478	(22,788)
General and administrative expense(1)		(3,311)	(451)		(3,762)
Depreciation and amortization expense		(1,668)	(5,153)		(6,821)
Share of net income of Frontier		406			406
Operating income		1,305	13,821		15,126
Interest expense	(3,894)	(489)	(851)		(5,234)
Intercompany interest income (expense)		5,946	(5,946)		
Equity earnings	13,798	7,158		(20,956)	
Other income (expense)	(14)	151	82		219
Income tax (expense) benefit		(273)	52		(221)
Net income	$ 9,890	$ 13,798	$ 7,158	$ (20,956)	$ 9,890

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

	Statement of Income Nine Months Ended September 30, 2005				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands)				
Net operating revenues	$	$ 55,085	$ 106,503	$ (5,046)	$ 156,542
Operating expenses		(31,461)	(45,650)	5,046	(72,065)
Line 63 oil release costs			(2,000)		(2,000)
General and administrative expense(1)		(11,420)	(1,567)		(12,987)
Accelerated long-term incentive plan compensation expense		(2,675)	(440)		(3,115)
Transaction costs	(893)	(914)			(1,807)
Depreciation and amortization expense		(4,893)	(14,802)		(19,695)
Share of net income of Frontier		1,363			1,363
Operating income	(893)	5,085	42,044		46,236
Interest expense	(12,925)	(2,322)	(2,432)		(17,679)
Intercompany interest income (expense)		19,051	(19,051)		
Equity earnings	41,397	19,691		(61,088)	
Other income	228	780	379		1,387
Income tax expense		(888)	(1,249)		(2,137)
Net income	$ 27,807	$ 41,397	$ 19,691	$ (61,088)	$ 27,807

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

	Statement of Income Nine Months Ended September 30, 2004				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating adjustments	Total
	(in thousands)				
Net operating revenues	$	$ 49,283	$ 88,958	$ (4,491)	$ 133,750
Operating expenses		(29,928)	(37,135)	4,491	(62,572)
General and administrative expense(1)		(10,529)	(723)		(11,252)
Depreciation and amortization expense		(4,911)	(12,865)		(17,776)
Share of net income of Frontier		1,190			1,190
Operating income		5,105	38,235		43,340
Interest expense	(4,648)	(7,909)	(1,186)		(13,743)
Write-off of deferred financing costs and interest rate swap termination expense		(2,901)			(2,901)
Intercompany interest income (expense)		14,564	(14,564)		
Equity earnings	31,752	22,732		(54,484)	
Other income (expense)	(9)	434	181		606
Income tax (expense) benefit		(273)	66		(207)
Net income	$ 27,095	$ 31,752	$ 22,732	$ (54,484)	$ 27,095

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

	Statement of Cash Flows Nine Months Ended September 30, 2005				
	Parent	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Total**
	(in thousands)				
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net income	$ 27,807	$ 41,397	$ 19,691	$ (61,088)	$ 27,807
Adjustments to reconcile net income to net cash provided by operating activities:					
Equity earnings	(41,397)	(19,691)		61,088	
Distributions from subsidiaries	46,224	31,888		(78,112)	
Depreciation, amortization and other	514	8,645	15,097		24,256
Net changes in operating assets and liabilities	8,877	9,601	1,948	(6,834)	13,592
NET CASH PROVIDED BY OPERATING ACTIVITIES	42,025	71,840	36,736	(84,946)	65,655
CASH FLOWS FROM INVESTING ACTIVITIES					
Acquisition		(457,352)			(457,352)
Additions to property, equipment and other		(14,729)	(16,349)		(31,078)
Intercompany	(465,633)			465,633	
NET CASH USED IN INVESTING ACTIVITIES	(465,633)	(472,081)	(16,349)	465,633	(488,430)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	427,090	395,844	(17,293)	(380,687)	424,954
Effect of translation adjustment			213		213
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	3,482	(4,397)	3,307		2,392
CASH AND CASH EQUIVALENTS, beginning of reporting period	2,713	17,523	3,147		23,383
CASH AND CASH EQUIVALENTS, end of reporting period	$ 6,195	$ 13,126	$ 6,454	$	$ 25,775

	Statement of Cash Flows Nine Months Ended September 30, 2004				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
	(in thousands)				
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net income	$ 27,095	$ 31,752	$ 22,732	$ (54,484)	$ 27,095
Adjustments to reconcile net income to net cash provided by operating activities:					
Equity earnings	(31,752)	(22,732)		54,484	
Distributions from subsidiaries	41,800	35,012		(76,812)	
Depreciation, amortization and other	176	8,127	12,837		21,140
Net changes in operating assets and liabilities	4,550	(10,783)	(6,893)	7,111	(6,015)
NET CASH PROVIDED BY OPERATING ACTIVITIES	41,869	41,376	28,676	(69,701)	42,220
CASH FLOWS FROM INVESTING ACTIVITIES					
Acquisitions			(139,000)		(139,000)
Additions to property, equipment and other		(7,633)	(4,510)		(12,143)
Intercompany	(369,675)	(96,267)		465,942	
NET CASH USED IN INVESTING ACTIVITIES	(369,675)	(103,900)	(143,510)	465,942	(151,143)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	328,210	63,622	118,161	(396,241)	113,752
NET DECREASE IN CASH AND CASH EQUIVALENTS	404	1,098	3,327		4,829
CASH AND CASH EQUIVALENTS, beginning of reporting period	746	8,603	350		9,699
CASH AND CASH EQUIVALENTS, end of reporting period	$ 1,150	$ 9,701	$ 3,677	$	$ 14,528

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

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

Forward-Looking Statements

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

We caution you that the forward-looking statements in this quarterly report on Form 10-Q are subject to all of the risks and uncertainties, many of which are beyond our control, incident to gathering, transporting, storing, and distributing crude oil, refined products and other related products, and buying and selling crude oil. For a more detailed description of these and other factors that may affect the forward-looking statements, please read Risk Factors contained in our annual report on Form 10-K for the year ended December 31, 2004, our Prospectus Supplement filed pursuant to Rule 424(b)(5) on September 9, 2005, as well as other filings with the SEC. The risk factors could cause our actual results to differ materially from those contained in any forward-looking statement. You should not put undue reliance on these forward-looking statements. We disclaim any obligation to announce publicly the result of any revision to any of the forward-looking statements to reflect future events or developments.

Introduction

The following discussion of the financial condition and results of operations of Pacific Energy Partners, L.P. should be read together with the condensed consolidated financial statements and the notes thereto set forth elsewhere in this report. The discussion set forth in this section pertains to our unaudited condensed consolidated balance sheets, statements of income, statements of cash flows and statement of partners capital.

This report on Form 10-Q should be read in conjunction with our annual report on Form 10-K for the year ended December 31, 2004.

Overview

We are a publicly traded limited partnership that was, during the period of this report, engaged principally in the business of gathering, transporting, storing and distributing crude oil and related products in California and the Rocky Mountain region of the U.S. and in Alberta, Canada. We generated revenue primarily by charging tariff rates for transporting crude oil on our pipelines and by leasing storage capacity. We also buy and sell crude oil, activities that are complementary to our pipeline transportation business (see Recent Developments Acquisition of Assets from Valero, L.P. below). We conduct our business through two business segments: the West Coast Business Unit and the Rocky Mountain Business Unit.

We are managed by our general partner, Pacific Energy GP, LP (General Partner), which is in turn managed by its general partner, Pacific Energy Management LLC (PEM or Managing General Partner). PEM has a board of directors that manages the business and affairs of PEM and, thus, indirectly manages the business and affairs of our General Partner and the Partnership.

Recent Developments

Acquisition of Assets from Valero, L.P.

On September 30, 2005, we completed the purchase of certain terminal and pipeline assets (the Valero Acquisition) from Support Terminals Operating Partnership, L.P., Kaneb Pipe Line Operating Partnership, L.P. and Shore Terminals LLC (the Sellers) for an aggregate purchase price of approximately $455 million, plus $12.0 million for the assumption of certain environmental and operating liabilities and $3.4 million for closing costs. 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 assets purchased consist of (i) the Martinez terminal and Richmond terminal in the San Francisco, California area, (ii) the North Philadelphia and South Philadelphia terminals and the Paulsboro, New Jersey terminal in the Philadelphia, Pennsylvania area, and (iii) a 550-mile refined products pipeline with four terminals in the U.S. Rocky Mountains.

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, the South Philadelphia and the Paulsboro, New Jersey 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 refined products pipeline system, 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 West Pipeline System has various segments with different receipt and delivery points. The trunk line of the pipeline system has a current throughput capacity that ranges from approximately 35,000 to 40,000 barrels per day, depending on the segment.

We funded the Valero Acquisition through a combination of 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 our new revolving credit facility (see below for a discussion of these new financing arrangements).

Equity and Debt Offerings

On September 14, 2005, we sold 4,550,000 common units at a public offering price of $32.00 per unit. On September 16, 2005, the underwriters exercised their over-allotment option and purchased an additional 682,500 common units at the same price. Net proceeds from the offering and exercise of the underwriters option, including our General Partner s contribution of $3.4 million, totaled approximately $163.4 million after deducting underwriting fees and offering expenses of $7.4 million. We used net proceeds from the equity offering to partially fund the Valero Acquisition.

On September 30, 2005, we sold 4,300,000 units pursuant to a Common Unit Purchase Agreement with certain institutional investors at a price of $30.75 per unit. We received net proceeds of $131.8 million for the sale of the common units, including our General Partner s contribution of $2.7 million, which were used to partially fund the Valero Acquisition. We also entered into a Registration Rights Agreement with the institutional investors, whereby we agreed to file a registration statement with the SEC for the resale from time to time of the privately placed common units, such filing to be made within 90 days after the closing, and for the Partnership thereafter to use commercially reasonable efforts to cause the shelf registration statement to become or be declared effective by the SEC within 180 days after the closing date.

On September 23, 2005, we 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. The notes were sold for 99.544% of face value resulting in an effective interest rate of 6.3125% to maturity. Net proceeds of $171.0 million from the sale of the notes, after deducting $0.8 million discount and offering expenses of $3.2 million, were used to partially fund the Valero Acquisition. Additionally, the Partnership entered into a registration rights agreement whereby it agreed, among other things, to file a registration statement with the SEC within 90 days after the issue date of the notes enabling holders of the notes to exchange the privately placed notes for publicly registered notes with substantially identical terms, and to file a shelf registration statement for the resale of the notes in certain circumstances. If the Partnership does not comply with its obligations under the registration rights agreement, the interest rate of the notes will increase.

New Revolving Credit Facility

On September 30, 2005, we entered into a new five-year $400 million senior secured revolving credit facility (the New Credit Facility) that replaced our 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, and we may prepay all loans under the New Credit Facility without premium or penalty. Obligations under the New Credit Facility are guaranteed by all of our subsidiaries except those for which regulatory approval is required and are secured by substantially all of our assets, excluding property held by the non-guaranteeing subsidiaries. The New Credit Facility is recourse to us and the guarantors, but non-recourse to our General Partner.

Included in the New Credit Facility is a Canadian sub-facility. The Canadian sub-facility currently has a limit of U.S.$100 million, but can be adjusted from time to time by us. The Canadian sub-facility includes an option for us to receive loans in either U.S. dollars or Canadian dollars.

Purchase of Crude Oil and Contracts

On July 1, 2005, we 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 assets were purchased by the Partnership s Pacific Marketing and Transportation (PMT) subsidiary.

Line 63 Crude 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 induced by heavy rainfall in the Pyramid Lake area of Los Angeles County. Over the period March 2005 through March 2006, we expect to incur an estimated total of $19.5 million for oil containment and clean-up of the impacted areas, future monitoring costs, potential third-party claims and penalties, and other costs, excluding pipeline repair costs. Through September 30, 2005, we had incurred approximately $14.1 million of the total expected oil release costs for work performed through such date.

We have a pollution liability insurance policy with a $2.0 million deductible, and 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. Although we believe we are entitled, subject to the $2.0 million deductible, to recover substantially all of our clean-up costs and third-party claims associated with the release, there is no absolute assurance that this will be the case. As of September 30, 2005, we have recovered $8.7 million from insurance and accrued a receivable of $8.8 million for insurance receipts we deem probable. As new information becomes available in future periods, our initial estimates of costs and recoveries may change.

We recorded $2.0 million in net costs in Line 63 oil release costs in the accompanying condensed consolidated statements of income for the nine months ended September 30, 2005. The $2.0 million net oil release costs consist of $19.5 million of accrued costs relating to the release, net of insurance recovery of $8.7 and accrued insurance receipts of $8.8 million.

On April 18, 2005, we received the necessary approvals to begin the repair of Line 63, and Line 63 was returned to operation. During the time the pipeline was out of service, we transferred significant volumes of light crude oil, on a temporary basis, from Line 63 to Line 2000, to mitigate the impact on customers and limit the potential loss of revenue. We also asked our customers to shift volumes of OCS crude oil from Line 63 to Line 2000. The permanent repair of Line 63 was completed in October 2005. We expensed $0.7 million, all in the second quarter, for the repair of Line 63 and expect to incur $1.7 million of Line 63 capital improvements in the third and fourth quarters of 2005.

On July 21, 2005, the California Public Utilities Commission (CPUC) approved our request to implement a temporary surcharge of $0.10 per barrel on our Line 63 long-haul tariff rates to recover our costs relating to this release together with other costs incurred or to be incurred as a result of problems caused by rain-induced earth movement and stream erosion. The surcharge was effective on August 1, 2005. We are required under the terms of the CPUC decision that approved the surcharge to substantiate in subsequent filings with the CPUC the actual costs incurred by us as a result of the Line 63 damage and our entitlement to the surcharge amounts received by us.

Sale of The Anschutz Corporation s Interest in the Partnership

On March 3, 2005, The Anschutz Corporation completed the sale of its 36.6% interest in the Partnership to LB Pacific, LP (LBP), an entity formed by Lehman Brothers Merchant Banking Group (LBMB). The acquisition by LBP (the LB Acquisition) included the purchase of a 100% ownership interest in Pacific Energy GP, Inc. (predecessor of Pacific Energy GP, LP), which owned (i) a 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 34.6% limited partner interest. 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, a Delaware limited partnership (together with its predecessors, the General Partner). The general partner of Pacific Energy GP, LP is Pacific Energy Management LLC, a Delaware limited liability company (PEM or the Managing General Partner), which is 100% owned by LBP. Immediately following the closing of the LB Acquisition, our General Partner distributed the 10,465,000 subordinated units of the Partnership to LBP.

In connection with the conversion of our General Partner to a limited partnership, our General Partner ceased to have a board of directors, and is now managed by PEM, its general partner. 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 our General Partner and the Partnership. All of the officers and employees of our General Partner were transferred to the same positions with PEM, and the Board established the same committees as had been maintained by our General Partner prior to the LB Acquisition. PEM also adopted our General Partner s governance guidelines and its compensation structure and employee benefit plans and policies.

Pursuant to an Ancillary Agreement, LBP and The Anschutz Corporation reimbursed us $2.4 million, which represents the cost incurred by us in connection with a consent solicitation prepared and delivered to the holders of our 7 1⁄8% senior notes, due 2014 to approve certain amendments to the governing indenture, and for severance and other costs incurred in connection with the sale of our General Partner. We were required by generally accepted accounting principles to record $0.6 million as capitalized deferred financing costs and $1.8 million as an expense. The reimbursements were recorded as the General Partner s capital contribution.

On March 3, 2005, in connection with the change in control of our General Partner, all restricted units outstanding under the Long-Term Incentive Plan immediately vested pursuant to the terms of the grants. As a result, we issued 99,583 common units and recorded a compensation expense of $3.1 million.

Because the LB Acquisition, together with other market activity, resulted in a change in ownership of more than 50% of the Partnership within a one year period, federal income tax laws require a modification to the Partnership s 2005 taxable income. The modification will result in a reduction in depreciation for 2005. The reduction in depreciation in 2005 will lead to additional depreciation becoming available for recognition in future years. The modification of taxable income will not have any impact on the Partnership s consolidated financial statements. For unitholders that purchased units in our 2002 initial public offering, or 2003 or 2004 equity offerings, we estimate that the amount of taxable income for the years 2005 through 2008 will be less than 20% of the cash distributions made to unitholders. For investors that bought units in our recent public equity offering, we estimate that for the years 2005 through 2008, taxable income to such unit holders will be less than 10% of the cash distributions made to unitholders.

Business Fundamentals

Pipeline Transportation

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

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

The tariff rates we charge on Line 2000 and the Line 63 system are regulated by the CPUC. Tariffs on Line 2000 are established based on market considerations, subject to certain contractual limitations. Tariffs on Line 63, which are cost-of-service based tariffs, are based upon the costs to operate and maintain the pipeline, as well as charges for the depreciation of the capital investment in the pipeline and the authorized rate of return. The tariff rates charged on our U.S. Rocky Mountain pipelines are regulated by either the Federal Energy Regulatory Commission (FERC) or the Wyoming Public Service Commission, generally under a cost-of-service approach.

Following are recent tariff rates increases on our pipelines:

- Effective August 1, 2005, we implemented a temporary surcharge of $0.10 per barrel on our Line 63 long-haul tariff rates to recover our costs relating to the oil release (see Line 63 Crude Oil Release above) together with other costs incurred or to be incurred as a result of rain-induced earth movement and stream erosion.

- On July 1, 2005 we increased the tariff rates on our U.S. Rocky Mountain pipelines by 3.6% based on the FERC index adjustment.

- On May 1, 2005 we increased the tariff rates on our Line 2000 by approximately 4.8%.

- Effective November 1, 2004, we increased the tariff rates on our Line 63 system by 9.5%. This increase was the first for Line 63 since 2001.

- On May 1, 2004, we increased the tariff rates on Line 2000 by approximately 6%. This index is reviewed annually.

These tariff rate increases on our West Coast pipelines partially mitigate the impact of declining throughput.

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

In the Rocky Mountains, our pipelines are connected to Canadian sources of crude oil, and in 2004 we completed the acquisition of the Rangeland system, giving us greater access to significant supplies of Canadian crude oil, including synthetic crude oil, which we believe will replace any long term U.S. Rocky Mountain production declines and meet growing demand in the U.S. Rocky Mountain region. We expect our initiating pump station in Edmonton, as well as a connection to a third party pipeline providing access to synthetic crude oil, to be completed in the fourth quarter of 2005. It appears in recent months that production in the U.S. Rocky Mountains may be increasing with the increased amount of natural gas related drilling, which results in increased volumes of crude oil and condensate. We believe, however, that the longer term production of crude oil in the U.S. Rocky Mountains will resume its historical decline.

Storage and Distribution

We provide storage and distribution services to refineries in the Los Angeles Basin through our Pacific Terminals (PT) storage and distribution system. The fundamental items impacting our storage and distribution revenue are the amount of storage capacity we have under lease, the lease rates for that capacity and the length of each lease. Demand for crude oil storage capacity tends to be more stable over time, and leases for crude oil storage capacity are usually long term (more than one year). Demand for storage capacity for other dark products is less stable, and varies depending on, among other things, refinery production runs and maintenance activities. Leases for dark products storage capacity are usually short term (less that one year). One of our business goals is to convert a number of dark products tanks to more flexible crude oil service (which can also accommodate other dark products); we are in the process of one such tank conversion and plan to convert a second tank in 2006.

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

Pipeline Buy/Sell Transportation

Throughput on our Rangeland system, which was acquired in the second quarter of 2004, varies with many of the same factors described in Pipeline Transportation above. In addition, following completion of our Edmonton initiation station, scheduled for the fourth quarter of 2005, throughput will vary with our success in attracting new supplies of synthetic crude oil to our system.

We are making significant changes to the revenue-generating capability of the Rangeland system by (i) combining and fully integrating all of our Canadian and U.S. Rocky Mountain pipeline assets under common management, (ii) establishing connections with other pipelines, thereby expanding the throughput capacity of the Rangeland system, and (iii) constructing a pump station and receiving terminal in Edmonton, Alberta. The development of the new receiving terminal and pump station, which will provide access to synthetic and other types of Canadian crude oil, continues to progress. Construction of this facility is expected to be completed in the fourth quarter of 2005, and additional tanks along the pipeline corridor are scheduled to be complete in the first quarter of 2006.

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

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

Effective December 1, 2004, we increased the location differentials on the Rangeland pipeline by an average of 10.8%.

Gathering and Marketing

Through our PMT subsidiary, we purchase, gather, and resell crude oil principally in California s San Joaquin Valley and in the Rocky Mountain area in the vicinity of our pipelines. Beginning in the third quarter of 2005, we also selectively purchase and resell crude oil in other areas as well, although this is not a focus area of the Partnership

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

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

Assets Acquired from Valero, L.P.

West Pipeline System. The West Pipeline System that we acquired from Valero is a common carrier petroleum products pipeline and terminals network. The system will generate revenues through transportation tariffs for volumes of petroleum products it ships. These tariffs vary depending upon where the product originates and, where ultimate delivery occurs. All transportation rates are market-based rates or published tariffs filed with the FERC and other state agencies. The products terminals on the pipeline system also will earn revenues by providing additional services.

Pacific Atlantic Terminals. The Martinez, Richmond, Paulsboro and Philadelphia terminals that we purchased from Valero are product (and, in the case of Martinez, crude oil) storage and terminaling facilities that will generate revenues primarily from fees that we charge customers for storage, throughput and other services.

Acquisitions and New Projects

We intend to continue to pursue acquisitions and new projects for development of additional midstream assets, including pipeline, storage and terminal facilities for both crude oil and refined products. We also intend to expand principally by acquisition into the natural gas storage and transportation businesses. We expect the acquisitions and new projects to be accretive to our cash flow and complement our existing businesses. We expect to fund acquisitions and new projects with a combination of debt and additional Partnership units, including common units. We expect to maintain a debt to total capitalization ratio of approximately 50% over time.

Operating Expenses

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

We do not have any employees, except in Canada. Our Managing General Partner provides employees to conduct our U.S. operations. We and our Managing General Partner collectively employ approximately 400 individuals who directly support our operations. We consider employee relations to be good. None of these employees are subject to a collective bargaining agreement, except for eight employees at our Paulsboro, New Jersey terminal, who are members of USW District 10-286 (Steel Workers), with whom we expect to execute a collective bargaining agreement that will end on October 1, 2009. Our Managing General Partner does not conduct any business other than with respect to the Partnership. All expenses incurred by our Managing General Partner are charged to us. Please read Note 4 Related Party Transactions in the footnotes to the condensed consolidated financial statement.

Impact of Foreign Exchange Rates

Assets and liabilities of our Canadian subsidiaries are translated to U.S. dollars using the applicable exchange rate as of the end of a reporting period. Revenues, expenses and cash flow are translated using the average exchange rate during the reporting period. The reported cash flow of our Canadian operations is based on the U.S. dollar equivalent of such amounts measured in Canadian dollars. The results of our Canadian operations and distributions from our Canadian subsidiaries to the Partnership may vary in U.S. dollar terms based on fluctuations in currency exchange rates irrespective of our Canadian subsidiaries underlying operating results. In addition, the amount of monies we repatriate from Canada will vary with fluctuations in currency exchange rates and may impact the cash available for distribution to our unitholders.

Critical Accounting Policies and Estimates

Our consolidated financial statements are prepared in conformity with accounting principles generally accepted in the United States, which require management to make estimates and assumptions that affect the reported amounts of the assets and liabilities and disclosures of contingent assets and liabilities as of the date of the balance sheet, as well as the reported amounts of revenue and expenses during the reporting period. We routinely make estimates and judgments about the carrying value of our assets and liabilities that are not readily apparent from other sources. Such estimates and judgments are evaluated and modified as necessary on an ongoing basis. We believe that of our significant accounting policies (see Note 1, Significant Accounting Policies, to our consolidated financial statements in our annual report on Form 10-K for the year ended December 31, 2004) and estimates, the following may involve a higher degree of judgment and complexity:

- We routinely apply the provisions of purchase accounting when recording our acquisitions. Application of purchase accounting requires that we estimate the fair value of the individual assets acquired and liabilities assumed (including environmental remediation liabilities). Additionally, we must determine whether an acquisition is considered to be a business or a set of net assets because excess purchase price can only be allocated to goodwill in a business combination. The valuation of the fair value of the assets involves a number of judgments and estimates. In our major acquisitions to date, we have engaged an outside valuation firm to provide us with an appraisal report, which we utilized in determining the purchase price allocation. The allocation of the purchase price to different asset classes impacts the depreciation expense we subsequently record. The principal assets we have acquired to date are property, pipelines, storage tanks and equipment.

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

- We accrue an estimate of the undiscounted costs of environmental remediation for work at identified sites where an assessment has indicated it is probable that cleanup costs are or will be required and may be reasonably estimated. In making these estimates, we consider information that is currently available, existing technology, enacted laws and regulations, and our estimates of the timing of the required remedial actions. We may use outside environmental consultants to assist us in making these estimates. We also are required to estimate the amount of any probable recoveries, including insurance recoveries. In addition, generally accepted accounting principles require us to establish liabilities for the costs of asset retirement obligations when the retirement date is determinable. We will record such liabilities only when such date is determinable.

- From time to time, a shipper or group of shippers may initiate a regulatory proceeding or other action, challenging the tariffs we charge or have charged. In such cases, we assess the proceeding on an ongoing basis as to its likely outcome, in order to determine whether to accrue for a future expense. We use outside regulatory lawyers and financial experts to assist us in these assessments.

- Our inventory of crude oil for our PMT gathering operations, our Canadian operations and any inventory earned through our tariffs for the transportation of crude oil in our common carrier pipelines is carried on our books at the lower of cost or market value, unless it is hedged, in which case it is carried at market. On any unhedged portion, we are exposed to the potential for a write-down to market value.

Results of Operations

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

Oil release on Line 63. As a result of the March 23, 2005 release of crude oil from PPS s Line 63, we recorded $2.0 million net oil release costs in the first quarter of 2005, consisting of $19.5 million of accrued costs relating to the release, net of insurance recovery of $8.7 million and accrued insurance receipt of $8.8 million. The discussion in Recent Developments describes the nature of these estimates and the potential for these estimates to increase or decrease in future periods.

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

Transaction costs. Pursuant to an Ancillary Agreement, LBP and The Anschutz Corporation reimbursed us $2.4 million for the cost incurred in connection with a consent solicitation prepared and delivered to the holders of our 7⅛% senior notes to approve certain amendments to the governing indenture and for severance and other costs incurred in connection with the sale of our General Partner. We were required by generally accepted accounting principles to record $0.6 million as capitalized deferred financing costs and $1.8 million as an expense, both in the first quarter of 2005. The reimbursements were recorded as a partner s capital contribution.

Write-off of deferred financing cost and interest rate swap termination expense. In the second quarter of 2004, we recorded an expense related to the unamortized portion of deferred financing costs of $2.3 million for our term loan, which was repaid in 2004, and incurred $0.6 million of expense to terminate related interest rate swaps.

Three Months Ended September 30, 2005 Compared to Three Months Ended September 30, 2004

Summary

Net income for the three months ended September 30, 2005 was $12.2 million, or $0.39 per diluted limited partner unit, compared to $9.9 million, or $0.33 per diluted limited partner unit, for the three months ended September 30, 2004.

The result of operations for the three months end September 30, 2005 reflects the benefit of (i) increased pipeline volumes in the Rocky Mountains, (ii) higher tank utilization and additional storage capacity for Pacific Terminals and (iii) higher location differentials on the Rangeland system and greater marketing income. These increases were partly offset by (i) tank maintenance on our Pacific Terminals storage and distribution system and (ii) lower volumes on our West Coast pipelines.

Segment Information

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

West Coast	**Three Months Ended September 30, 2005 (In thousands)**	**2004**	**Change**	**Percent**
Operating income	$ 9,813	$ 11,355	$ (1,542)	(14)%
Operating data:				
Pipeline throughput (bpd)	104.4	139.7	(35.3)	(25)%

For the three months ended September 30, 2005, operating income was $9.8 million, compared to $11.4 million for the three months ended September 30, 2004. West Coast pipeline volumes for the three months ended September 30, 2005 were approximately 25% lower than the third quarter of 2004 because in 2005 there was (i) diversion by our customers of some volumes north to San Francisco, reducing the supply of crude oil available to be moved south to Los Angeles, (ii) refinery maintenance in the L.A. Basin, which resulted in lower volumes moving south to Los Angeles, (iii) lower OCS production due to maintenance activities, and (iv) natural production decline of San Joaquin Valley crude and OCS crude oil. These conditions were partially offset by increased tariffs on our pipelines, higher operating income on our Pacific Terminals storage and distribution system resulting from higher lease fees, increased tank utilization and an increase in tank storage capacity. Increases in revenues on our Pacific Terminals storage and distribution system were partially offset by higher tank maintenance costs.

Rocky Mountains	**Three Months Ended September 30, 2005 (In thousands)**	**2004**	**Change**	**Percent**
Operating income	$ 13,644	$ 7,533	$ 6,111	81 %
Operating data (bpd):				
Rangeland pipeline system:				
Sundre North	19.3	21.8	(2.5)	(11)%
Sundre South	48.1	46.8	1.3	3 %
Western Corridor system	26.8	23.1	3.7	16 %
Salt Lake City Core system	125.6	122.6	3.0	2 %
Frontier pipeline	49.6	51.4	(1.8)	(4)%

For the three months ended September 30, 2005, operating income was $13.6 million, compared to $7.5 million for the three months ended September 30, 2004. Increased market share for pipeline shipments of crude oil to Billings, Montana and increased demand by the Salt Lake City, Utah refineries helped drive higher pipeline volumes on the U.S. Rocky Mountain systems. We also increased some tariffs on July 1, 2005. Rangeland s operating income increased due to higher location differentials, higher pipeline volumes moving south and increased marketing income. Frontier pipeline volumes decreased in the third quarter of 2005 over the same period in 2004, because of reduced volumes of synthetic crude oil.

During the quarter ended September, 30, 2005, management identified a control deficiency related to the accounting for inventory and cost of goods sold for our Rangeland pipeline since its acquisition in May 2004. This deficiency resulted in an understatement of Pipeline buy/sell transportation revenue (revenue is presented net of cost of goods sold) and a corresponding understatement of the inventory balance in prior quarters. Although this deficiency resulted in an error in prior quarters, management assessed the materiality of the impact on the second, third and fourth quarters of 2004 and the first and second quarters of 2005 and concluded that this error was not material to the previously issued historical financial statements, nor was the cumulative correction material to the third quarter 2005 financial statements. In the quarter ended September 30, 2005, the cumulative correction resulted in an increase to the Rocky Mountain Business Unit s pre-tax income of $1.2 million (resulting in a $0.7 million after tax increase to the Partnership s net income). There was no impact to the Partnership s cash flow from operating activities for any of the prior quarters or for the quarter ended September 30, 2005. Management concluded that this control deficiency was not a material weakness due to the existence of compensating controls. Management has implemented new procedures to fully remediate the control deficiency.

Statement of Income Discussion and Analysis

Revenues	**Three Months Ended September 30, 2005**	**2004**	**Change**	**Percent**
	(In thousands)			
Pipeline transportation revenue	$ 27,283	$ 28,160	$ (877)	(3)%
Storage and distribution revenue	9,731	8,391	1,340	16 %
Pipeline buy/sell transportation revenue	11,683	7,972	3,711	47 %
Crude oil sales, net of purchases:				
Crude oil sales	194,724	106,760	87,964	82 %
Crude oil purchases	(188,901)	(103,192)	85,709	83 %
Crude oil sales, net of purchases	5,823	3,568	2,255	63 %
Net revenue	$ 54,520	$ 48,091	$ 6,429	13 %

Increased pipeline transportation revenues were realized by our U.S. Rocky Mountain pipelines. Volumes on the U.S. Rocky Mountain pipelines were higher due to increased demand by refineries in Billings, Montana, Casper, Wyoming and Salt Lake City, Utah area refineries. Our West Coast pipelines had lower revenues compared to the prior year for several reasons, as noted above. The reduction in volumes on our West Coast pipeline was partially offset by increased tariff rates that were implemented in the fourth quarter of 2004 on Line 63, in the second quarter of 2005 for Line 2000, and a temporary surcharge implemented in the third quarter of 2005 for Line 63 to recover rain-related repair costs and our costs for the Pyramid Lake oil release.

Storage and distribution revenue is higher than the prior year due to higher lease fees, increased tank utilization and an increase in storage capacity (an idle 72,000 barrel tank was put back into service at the end of the third quarter of 2004).

Pipeline buy/sell transportation revenues of $11.7 million is higher than the prior year because of higher location differentials charged on the Rangeland pipelines and higher volumes being transported south to the Canadian border. In December 2004, we increased the location differentials on the Rangeland pipeline by an average of 10.8%.

The increase in net crude oil sales for the three months ended September 30, 2005 was the result of additional contracts acquired on July 1, 2005 as well as from increased margin gathering activities in our West Coast operations. Additionally, in 2004, margins on one particular contract declined as the difference between purchases made on a WTI price basis and sales on a West Coast price basis deviated from historical norms over the period from September 2004 through March 2005. This contract expired on March 31, 2005.

Expenses	**Three Months Ended September 30, 2005**	**2004**	**Change**	**Percent**
	(In thousands)			
Operating expenses	$ 25,019	$ 22,788	$ 2,231	10 %
General and administrative expense	4,115	3,762	353	9 %
Depreciation and amortization expense	6,560	6,821	(261)	(4)%
	$ 35,694	$ 33,371	$ 2,323	7 %

Operating expenses increased for several reasons. First, we had higher tank maintenance costs on our Pacific Terminals storage and distribution system and a greater number of major maintenance projects elsewhere. Second, we experienced higher power and trucking costs, both of which were incurred to generate increased revenues.

Increases in general and administrative expense resulted from our corporate development activities and from increased crude oil marketing, which were partially offset by the absence of an expense for the long term incentive plan.

Depreciation and amortization expense decreased primarily because of assets that have now been fully depreciated.

Other Income and Expense	**Three Months Ended September 30, 2005**	**2004**	**Change**	**Percent**
	(In thousands)			
Share of net income of Frontier	$ 516	$ 406	$ 110	27 %
Interest expense	$ 6,237	$ 5,234	$ 1,003	19 %
Other income	$ 494	$ 219	$ 275	126 %
Income tax expense	$ 1,433	$ 221	$ 1,212	548 %

The increase in our share of Frontier s net income was mainly attributable to lower operating costs at Frontier.

The increase in interest expense was due to additional borrowings incurred to fund our profit generating capital spending projects. In addition, we completed a senior notes offering to partially fund the acquisition of assets from Valero, L.P. on September 23, 2005 and, pending the closing of the acquisition, temporarily invested the proceeds, which resulted in increased other income as noted below. Our weighted average borrowings during the three months ended September 30, 2005 were $352 million compared to $335 million in the corresponding period in 2004. In addition, floating interest rates were higher in 2005, which resulted in a weighted average interest rate of 7.0% for the three months ended September 30, 2005 compared to a weighted average interest rate of 5.8% for the corresponding period in 2004.

Other income of $0.5 million for the period ended September 30, 2005 was $0.3 million greater than the corresponding period in 2004 due to increased interest income and other items.

Income tax expense is a function of the income of our Canadian subsidiaries, which are taxable entities. In addition, certain kinds of repatriation of funds into the U.S. subject the Partnership to Canadian withholding tax.

Nine Months Ended September 30, 2005 Compared to Nine Months Ended September 30, 2004

Summary

Net income for the nine months ended September 30, 2005 was $27.8 million, or $0.96 per diluted limited partner unit, compared to $27.1 million, or $0.94 per diluted limited partner unit, for the nine months ended September 30, 2004.

Net income for the nine months ended September 30, 2005 includes nine months of operations of the Rangeland system. The Rangeland system was acquired on May 11, 2004 and expanded by the acquisition of the MAPL pipeline on June 30, 2004.

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

	Nine Months Ended September 30,			
	2005	**2004**	**Change**	**Percent**
	(In thousands)			
Net income	$ 27,807	$ 27,095	$ 712	3 %
Add: Line 63 oil release costs	2,000		2,000	
Accelerated long-term incentive compensation expense	3,115		3,115	
Transaction costs	1,807		1,807	
Write-off of deferred financing cost and interest rate swap termination expense		2,901	(2,901)	
	$ 34,729	$ 29,996	$ 4,733	16 %
Diluted weighted average limited partner units	30,051	28,125	1,926	7 %

The improvement in the results of operations, excluding the effect of the unusual items mentioned above, reflects the benefit of (i) the operations of the Rangeland system acquired in May 2004, (ii) higher pipeline transportation revenues on the Rocky Mountain pipelines, and (iii) higher storage and distribution revenues on our Pacific Terminal systems.

These increases were partially offset by (i) lower gathering margins, which were below average for the nine months ended September 30, 2005 and above average in the nine months ended September 30, 2004, (ii) unscheduled repairs and maintenance associated with earth movement and stream erosion problems caused by heavy rainfall in Southern California during the early part of 2005, and (iii) unscheduled repairs for our Pacific Terminals storage facilities in 2005. The lower margins on our West Coast gathering activities were due to competitive pricing pressures as a result of cheaper foreign crude entering the West Coast markets.

There were 30.1 million weighted average limited partner units outstanding in the nine months ended September 30, 2005, approximately 7% more limited partner units than the 28.1 million weighted average units outstanding in the nine months ended September 30, 2004, primarily due to the sale in mid-September 2005 of additional common units to partially fund the acquisition of assets from Valero, L.P. on September 30, 2005.

Segment Information

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

West Coast	**Nine Months Ended September 30, 2005**	**2004**	**Change**	**Percent**
	(In thousands)			
Operating income	$ 31,962	$ 37,702	$ (5,740)	(15)%
Add: Line 63 oil release cost	2,000		2,000	
	$ 33,962	$ 37,702	$ (3,740)	(10)%
Operating data:				
Pipeline throughput (bpd)	120.8	137.6	(16.8)	(12)%

For the nine months ended September 30, 2005, operating income excluding the effect of the $2.0 million expense for the Line 63 oil release was $34.0 million, compared to $37.7 million for the nine months ended September 30, 2004. The reasons for the decrease were as follows:

- West Coast pipeline volumes for the nine months ended September 30, 2005 were approximately 12% lower than the same period in 2004. During the nine months ended September 30, 2005, volumes were impacted by Los Angeles area refinery maintenance and lower San Joaquin Valley and OCS production, resulting in lower volumes moving south to Los Angeles. There were $2.4 million of unscheduled repairs and maintenance associated with earth movement and stream erosion problems at various locations along both Line 63 and Line 2000, caused by heavy rainfall in Southern California. The revenue effect of lower volumes was offset by incremental revenue from increased tariffs on Line 63 beginning November 1, 2004, on Line 2000 beginning May 1, 2005, and on Line 63 beginning August 2005 from a temporary surcharge to recover the rain-related repair costs and our Pyramid Lake oil release costs.

- PMT gathering margins were also lower in 2005 due to pricing pressures from discounted crude oil imports and margins on one particular contract which expired on March 31, 2005.

Storage and distribution revenues were higher during the nine months ended September 30, 2005, due to higher rates of tank utilization and 72,000 barrels of additional tank capacity being made available as a result of an idle tank being put into service at the end of the third quarter of 2004. These increased revenues were partially offset by increased tank maintenance costs.

Rocky Mountains	**Nine Months Ended September 30, 2005**	**2004**	**Change**	**Percent**
	(In thousands)			
Operating income	$ 32,183	$ 16,890	$ 15,293	91 %
Operating data (bpd):				
Rangeland pipeline system:				
Sundre North	21.3	21.6	(0.3)	(1)%
Sundre South	45.3	47.6	(2.3)	(5)%
Western Corridor system	24.0	19.6	4.4	22 %
Salt Lake City Core system	119.8	116.1	3.7	3 %
Frontier pipeline	46.4	48.5	(2.1)	(4)%

For the nine months ended September 30, 2005, operating income was $32.2 million, compared to $16.9 million for the nine months ended September 30, 2004. The increase included the results of the Rangeland system, which was acquired on May 11, 2004. In addition, increased market share for pipeline shipments of crude oil to Billings, Montana, and increased demand by the Salt Lake City, Utah, refineries, helped drive higher pipeline volumes on the U.S. Rocky Mountain systems other than Frontier pipeline. Frontier pipeline volumes in 2005 were affected by a shortage of synthetic crude oil supply caused by a fire at a Suncor Energy, Inc. facility in December 2004. Shippers have now replaced these volumes with other types of crude oil and volumes returned to more normal levels in the second quarter of this year.

Statement of Income Discussion and Analysis

Revenues	Nine Months Ended September 30, 2005	2004	Change	Percent
	(In thousands)			
Pipeline transportation revenue	$ 83,067	$ 79,879	$ 3,188	4 %
Storage and distribution revenue	30,923	27,773	3,150	11 %
Pipeline buy/sell transportation revenue	28,905	11,662	17,243	148 %
Crude oil sales, net of purchases:				
Crude oil sales	439,380	293,125	146,255	50 %
Crude oil purchases	(425,733)	(278,689)	147,044	53 %
Crude oil sales, net of purchases	13,647	14,436	(789)	(5)%
Net revenue	$ 156,542	$ 133,750	$ 22,792	17 %

Increased pipeline transportation revenues were realized by our U.S. Rocky Mountain pipelines. Volumes on the U.S. Rocky Mountain pipelines were higher due to increased demand by refineries in Billings, Montana, Casper, Wyoming and Salt Lake City, Utah area refineries. The revenue effect of lower volumes on the West Coast pipelines was partly offset by higher tariffs.

Storage and distribution revenues were higher than the same period in 2004 due to higher rates of tank utilization and increased capacity being made available as a result of a 72,000 barrel idle tank being put into operation during the third quarter of 2004.

The increase in pipeline buy/sell transportation revenues of $17.2 million reflects a full nine months of operations of the Rangeland system, which was acquired on May 11, 2004, as well as an increase in location differentials on December 1, 2004.

The decrease in net crude oil sales for the nine months ended September 30, 2005 was primarily the result of lower margin gathering activities in our West Coast operations, particularly due to competitive pricing pressures from cheaper foreign crude entering the West Coast markets. Additionally, margins on one particular contract declined as the difference between purchases made on a WTI price basis deviated from historical norms over the period from September 2004 through March 2005. This contract expired on March 31, 2005. Higher oil prices increased gross sales and purchases values. In addition, we acquired additional crude oil contracts on July 1, 2005.

Expenses	**Nine Months Ended September 30, 2005**	**2004**	**Change**	**Percent**
	(In thousands)			
Operating expenses	$ 72,065	$ 62,572	$ 9,493	15 %
Line 63 oil release costs	2,000		2,000	
General and administrative expense	12,987	11,252	1,735	15 %
Accelerated long-term incentive plan compensation expense	3,115		3,115	
Transaction costs	1,807		1,807	
Depreciation and amortization expense	19,695	17,776	1,919	11 %
	$ 111,669	$ 91,600	$ 20,069	22 %

The increase in operating expense was related primarily to the acquisition of the Rangeland system on May 11, 2004. Operating expenses in the West Coast were also higher as a result of $2.4 million of unscheduled repairs and maintenance and expenses on Line 2000 and Line 63 resulting from earth movements and creek washouts caused by heavy rains. In addition, tank maintenance expense was greater for Pacific Terminals in 2005.

The Line 63 oil release costs are discussed in Recent Developments above.

The increase in general and administrative expense was associated with the integration and operation of the Rangeland acquisition and certain expensed costs for the Pier 400 project (see Capital Requirements below for a discussion of the Pier 400 Project). These items were not applicable in the corresponding period of 2004. In addition, we incurred more costs for acquisition evaluations in 2005. These increases were partly offset by reduced costs for the Long Term Incentive Plan included in general and administrative expense.

Transaction costs are discussed in Recent Developments above.

On March 3, 2005, in connection with the change in control of the General Partner, all restricted units outstanding under the Long-term Incentive Plan immediately vested. For the nine months ended September 30, 2005, we recognized $3.1 million in compensation expense as a result.

The increase in depreciation and amortization includes $2.3 million for depreciation on the Rangeland system. This increase was partly offset by lower depreciation on other assets reflecting assets that have now been fully depreciated.

Other Income and Expense	Nine Months Ended September 30, 2005	2004	Change	Percent
	(In thousands)			
Share of net income of Frontier	$ 1,363	$ 1,190	$ 173	15 %
Interest expense	$ 17,679	$ 13,743	$ 3,936	29 %
Write-off of deferred financing cost and interest rate swap termination expense	$	$ 2,901	$ (2,901)	
Other income	$ 1,387	$ 606	$ 781	129 %
Income tax expense	$ 2,137	$ 207	$ 1,930	932 %

The increase in our share of Frontier s net income was mainly attributable to lower operating costs at Frontier.

The increase in interest expense was due to borrowings incurred to partially fund the acquisition of the Rangeland system and due to higher floating interest rates. Our weighted average borrowings during the nine months ended September 30, 2005 were $359 million compared to $304 million in the corresponding period in 2004. In addition, floating interest rates were higher in 2005, which resulted in a weighted average interest rate of 6.6% for the period ended September 30, 2005 compared to a weighted average interest rate of 5.8% for the corresponding period in 2004.

The write-off of deferred financing cost and interest rate swap termination expense are discussed in Results of Operations above.

Other income of $1.4 million for the period ended September 30, 2005 was $0.8 million greater than the corresponding period in 2004 due to increased interest income and other items.

The increase in income tax expense for the nine months ended September 30, 2005 relates to the income of the Rangeland system acquired on May 11, 2004. Our Canadian subsidiaries are taxable entities and certain kinds of repatriation of funds into the U.S. are subject to Canadian withholding tax.

Liquidity and Capital Resources

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

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

We have received approval from the CPUC to sell surplus Pacific Terminals properties, which we believe are worth approximately $10 million. We expect to close on the sale of the first of these properties in November 2005 for net proceeds of $1.6 million, an amount approximately equal to its book value.

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

We expect, subject to Board approval, to increase our cash distribution to unitholders by $0.0425 per unit for the fourth quarter of 2005 to $0.555 per unit per quarter, or $2.22 per unit annually, as a result of the acquisition of assets from Valero, L.P. and the expected completion of our Edmonton, Alberta, initiating station in the fourth quarter of 2005.

Operating, Investing and Financing Activities

	Nine months Ended September 30, 2005 (In thousands)	2004	Change	Percent
Net cash provided by operating activities	$ 65,655	$ 42,220	$ 23,435	56 %
Net cash used in investing activities	(488,430)	(151,143)	(337,287)	(223)%
Net cash provided by (used in) financing activities	424,954	113,752	311,202	274 %

Net cash provided by operating activities

The increase in the net cash from operating activities of $23.4 million, or 56%, was primarily the result of a decrease in cash used for working capital.

Net cash from operating activities for the nine months ended September 30, 2005 was increased by approximately $20.3 million by working capital changes. Increases in accounts payable and other accrued liabilities and accrued crude oil purchases more than offset an increase in crude oil sales receivables.

Net cash used in investing activities

On September 30, 2005, we purchased certain terminal and pipeline assets from various subsidiaries of Valero, L.P. for an aggregate purchase of $455.0 million plus transaction costs of approximately $3.4 million, of which approximately $1.0 million was accrued at September 30, 2005. Separately, we also 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. Capital expenditures were $27.3 million in the nine months ended September 30, 2005, of which $3.1 million related to sustaining capital projects, $6.2 million related to transition projects, $13.1 million related to expansion and $4.9 million was for our continued development of the Pier 400 Project.

The amount of cash used in investing activities in 2004 relates primarily to our acquisition and development activities. The 2004 period includes $139.0 million related to the acquisition of the Rangeland system, including the MAPL pipeline. Capital expenditures for the nine months ended September 30, 2004 were $11.5 million of which $1.5 million related to sustaining capital projects, $1.2 million related primarily to the transition of the Pacific Terminals storage and distribution system and the Rangeland pipeline system, $6.3 million related to expansion and $2.5 million was for development of the Pier 400 Project.

Net cash provided by and used in financing activities

Cash provided by financing activities for the nine months ended September 30, 2005 include net proceeds of $295.2 million, including our General Partner contribution of $6.1 million, from our public and private equity offerings, $171.0 million net proceeds from the offering of our 6 1⁄4% senior notes, and net proceeds of $114.2 million under our new revolving credit facility. During the nine months ended September 30, 2005, we incurred net borrowings of $64.3 million under our previous U.S. and Canadian revolving credit facilities. In September 2005, we repaid in full the outstanding balance of $171.0 million under our previous U.S. and Canadian revolving credit facilities. Cash provided by financing activities for the nine months ended September 30, 2005 also include distributions of $46.2 million which were made to the limited partners and the General Partner and a $2.4 million contribution from TAC and LBP, to reimburse us for certain costs incurred in connection with the LB Acquisition.

The amount of cash provided by financing activities in 2004 of $113.8 million includes (i) net proceeds of $128.6 million from our equity offerings completed in March and April, 2004, which were used principally to partly fund our acquisition of the Rangeland system, (ii) $241.1 million net proceeds from the offering of our 7⅛% senior notes, which were used in part to repay our $225 million term loan, (iii) net proceeds of $11.1 million under our revolving credit facilities, and (iv) $41.8 million in distributions to the limited and general partner interests.

Capital Requirements

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

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

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

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

We have forecasted total capital expenditures for our existing operations of $53 million for 2005, including $10 million for the Pier 400 Project, $27 million for expansion projects, $8 million relating to the transition of the Rangeland system, $3 million for other transition capital projects, and $5 million for sustaining capital projects.

Pier 400

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

We initiated the environmental review and permitting for the Pier 400 project in June 2004 and expect to have the permits necessary for construction to begin in the second half of 2006. We entered into a project development agreement with two subsidiaries of Valero Energy Corporation that defines the facilities that we are to construct in the POLA. We and Valero Energy Corporation have also signed a terminaling services agreement with a 30-year, 50,000 bpd volume commitment from Valero Energy Corporation to support the terminal. These agreements are subject to the satisfaction of various conditions, including the execution of additional project related agreements and the achievement of certain project milestones, some of which have not been satisfied. We are negotiating these additional agreements and an extension of the project milestones with Valero, and we expect to reach an agreement. Negotiations for long-term commitments with additional customers are progressing.

Final construction of the Pier 400 Project is subject to the completion of a land lease agreement with the POLA, receipt of environmental and other approval, securing additional customer commitments, updating engineering and project cost estimates, ongoing feasibility evaluation, and financing. A final decision to proceed is expected to be made in the first half of 2006. We expect construction of the Pier 400 terminal to be completed and placed in service in late 2007.

We have capitalized approximately $15.4 million on the Pier 400 project through September 30, 2005, including $4.9 million for the nine months ended September 30, 2005. These expenditures include $7.3 million for emission reduction credits, an asset that is re-saleable if the project does not proceed. We anticipate funding the remaining pre-construction costs through the second quarter of 2006 from our revolving credit facility. Construction of the Pier 400 terminal is expected to be financed through a combination of debt and proceeds from the issuance of additional partnership units, including common units.

Debt Obligations

At September 30, 2005, our debt obligations include: (i) $114.2 million on our new senior secured revolving credit facility, including $19.2 million under the Canadian sub-facility, (ii) $247.5 million on our 7⅛% senior notes, due June 2014, (iii) $174.2 million on our 6¼% senior notes, due September 2015, and (iv) Cdn$4.6 million (U.S.$3.9 million) payable to the seller of the MAPL assets. For further discussion of these debt obligations see Note 5 Long-term Debt to the accompanying condensed consolidated financial statements.

As of September 30, 2005, $152.6 million of undrawn credit was available under the new senior secured revolving credit facility. With the consent of the administrative agent under the new revolving credit facility, we can increase credit availability up to an additional $116.4 million, based upon pro-forma EBITDA from future acquisitions.

Off-Balance Sheet Arrangements

As of September 30, 2005, we had standby letters of credit outstanding of $16.8 million for securing crude oil purchases and the MAPL note, both of which are reflected as liabilities on the balance sheet.

Accounting Pronouncements

In December 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 annual reporting period that begins after June 15, 2005. The Partnership has not yet determined the impact of the adoption of SFAS 123R on the Partnership s consolidated financial statements.

In December 2004, the FASB issued Statement of 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. The Statement is effective for fiscal periods beginning after June 15, 2005. The

Partnership does not expect the adoption of SFAS 153 to have a material impact on its 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 is effective for the Partnership no later than the end of fiscal years ending after December 15, 2005. The Partnership is in the process of determining the impact of FIN 47 on its consolidated financial statements.

In May 2005 The FASB issued Statement of 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.

ITEM 3. Quantitative and Qualitative Disclosures About Market Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. The principal market risks to which we are exposed are interest rate risk and crude oil price risk. Debt we incur under our credit facilities bears variable interest at the applicable base or prime rate, a rate based on Eurodollar or a rate based on Canadian Bankers Acceptances. We have used and will continue to use from time to time derivative instruments to hedge our exposure to variable interest rates. In addition, we have entered into swap agreements to convert a portion of our fixed rate senior notes into floating rate debt based on LIBOR.

We use, on a limited basis, certain derivative instruments (principally futures and options) to hedge our exposure to market price volatility related to our inventory or future sales of crude oil. We do not enter into speculative derivative activities of any kind. The fair market values of these derivative instruments are included in Other current assets in the accompanying consolidated balance sheets. In our gathering operations we purchase crude oil for subsequent transportation and resale primarily in the Los Angeles Basin. Changes in the fair value of our derivative instruments related to the fair value hedge of crude oil inventory are recognized in net income. For the nine months ended September 30, 2005 and 2004, crude oil sales, net of purchases were net of $1.7 million and $2.3 million in losses, respectively, reflecting changes in the fair value of derivative instruments in our gathering operations. Losses on derivatives were generally offset by gains in physical crude oil inventory positions. In addition, changes in the fair value of our derivative instruments related to the forecasted sale of crude oil, which qualify as cash flow hedges for accounting purposes, are deferred and reflected in accumulated other comprehensive income, a component of partners capital, until the related revenue is recognized in the consolidated statements of income. We expect to reclassify a net amount of $0.7 million of existing gains and losses into earnings over the next 12 months. For existing hedges, the maximum length of time over which we are hedging our exposure to future cash flows for forecasted transactions is 15 months. As of September 30, 2005, $0.5 million relating to the changes in the fair value of derivative instruments was included in accumulated other comprehensive income. In September 2005, we hedged a portion of our forecasted 2006 sales of crude oil by entering into cashless collars. Changes in price within the collar range are expensed and the effective portion of any price change outside of the collar range will be deferred and reflected in accumulated other comprehensive income .

In connection with our 7⅛% senior notes, due June 2014, we entered into interest rate swap agreements with an aggregate notional principal amount of $80.0 million to receive interest at a fixed rate of 7⅛% 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 on June 15, 2014 and are callable at the same dates and terms as the 7⅛% senior notes. We designated these swaps as a hedge of the change in the 7⅛% 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 the 7⅛% 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 September 30, 2005 we recorded an increase of $1.4 million in the fair value of interest rate swaps with an equal offsetting entry to the $80.0 million of 7⅛% senior notes. As of September 30, 2005, we assessed the hedge effectiveness of this interest rate swap and noted that no gain or loss from measuring ineffectiveness was required to be recognized.

We are subject to risks resulting from interest rate fluctuations as the interest cost on our credit facilities and the $80 million interest swap on the 7⅛% senior notes are based on variable rates. If the LIBOR or Canadian Bankers Acceptance discount rates were to increase 1.0% for the remainder of 2005 as compared to the rate at September 30, 2005, our interest expense for the remainder of 2005 would increase $0.5 million based on our outstanding debt at September 30, 2005.

Fair Value of Financial Instruments

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

	September 30, 2005		December 31, 2004	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(in thousands)			
Crude oil hedging futures	$ 1,444	$ 1,444	$ 400	$ 400
Fair value interest rate swaps	1,445	1,445	2,693	2,693
Long-term debt	539,789	554,637	357,163	373,265

As of September 30, 2005 and December 31, 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 rate on the 7⅛% senior notes, due June 2014, and the 6¼% senior notes, due September 2015, are fixed, except for $80 million which is subject to an interest rate swap agreement, and the fair value is determined from a broker s price quotes at September 30, 2005 and December 31, 2004.

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

ITEM 4. Controls and Procedures

Disclosure Controls and Procedures

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

Based on their evaluation as of September 30, 2005, our principal executive officer and principal financial officer have concluded that, as of the end of the period covered by this report, our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the Exchange Act) are effective to ensure that the information required to be disclosed by us in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

Internal Control Over Financial Reporting

Our management, including the Chief Executive Officer and Chief Financial Officer, have evaluated our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) as of September 30, 2005, and have concluded that there has not been any change during our most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. Legal Proceedings

In connection with the Valero Acquisition, we have assumed defense of Support Terminals Services, Inc. (ST Services) in a lawsuit filed in New Jersey state court in 2003 by ExxonMobil Corporation (ExxonMobil). We have also assumed any liability that might be imposed on ST Services as a result of the suit. In the suit, ExxonMobil seeks $400,000 for remediation costs it has paid, 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 on the same defendants. These costs are associated with the Paulsboro, New Jersey terminal that was acquired by us. ExxonMobil claims that the costs are related to releases at the site subsequent to its sale of the terminal to GATX in 1990 and that any remaining remediation requirements are the responsibility of GATX Corporation, Kinder Morgan, and ST Services.

See also discussion of legal proceedings in Note 10 Contingencies in the accompanying condensed consolidated financial statements.

ITEM 6. Exhibits

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

Exhibit Number	**Description**
Exhibit 4.3	Registration Rights Agreement, dated September 23, 2005, among the Issuers and the Initial Purchasers (Incorporated by reference to Pacific Energy Partners, L.P. s Form 8-K filed on September 28, 2005, Exhibit 4.3)
Exhibit 10.1	Credit Agreement, dated as of September 30, 2005, among Pacific Energy Partners L.P., Rangeland Pipeline Company, Bank of America, NA and other lenders party thereto (Incorporated by reference to Pacific Energy Partners, L.P. s Form 8-K filed on October 6, 2005, Exhibit 10.1)
Exhibit 10.2	Registration Rights Agreement, dated September 30, 2005, among Pacific Energy Partners L.P. and the Purchasers (Incorporated by reference to Pacific Energy Partners, L.P. s Form 8-K filed on August 11, 2005, Exhibit A to Exhibit 10.1)
* Exhibit 12.1	Statement of Computation of Ratio of Earnings to Fixed Charges
* Exhibit 31.1	Certification of Principal Executive Officer of Pacific Energy Management LLC, General Partner of Pacific Energy GP, LP, General Partner of Pacific Energy Partners, L.P., as required by Rule 13a-14(a) of the Securities Exchange Act of 1934
* Exhibit 31.2	Certification of Principal Financial Officer of Pacific Energy Management LLC, General Partner of Pacific Energy GP, LP, General Partner of Pacific Energy Partners, L.P., as required by Rule 13a-14(a) of the Securities Exchange Act of 1934
Exhibit 32.1	Certification of Chief Executive Officer of Pacific Energy Management LLC, General Partner of Pacific Energy GP, LP, General Partner of Pacific Energy Partners, L.P., pursuant to 18 U.S.C. §1350
Exhibit 32.2	Certification of Chief Financial Officer of Pacific Energy Management LLC, General Partner of Pacific Energy GP, LP, General Partner of Pacific Energy Partners, L.P., pursuant to 18 U.S.C. §1350

* Filed herewith.

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

SIGNATURES

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

PACIFIC ENERGY PARTNERS, L.P.

By: PACIFIC ENERGY GP, LP, its General Partner

By: PACIFIC ENERGY MANAGEMENT LLC, its General Partner

By: /s/ IRVIN TOOLE, JR.
Irvin Toole, Jr.
President, Chief Executive Officer and Director
(Principal Executive Officer)
November 14, 2005

By: /s/ GERALD A. TYWONIUK
Gerald A. Tywoniuk
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial and Accounting Officer)
November 14, 2005

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