PLAINS ALL AMERICAN PIPELINE LP
Form S-1/A
May 20, 2005

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As filed with the Securities and Exchange Commission on May 20, 2005

Registration No. 333-

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Amendment No. 1
to
FORM S-1

REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933

PLAINS ALL AMERICAN PIPELINE, L.P.

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**4610**	**76-0582150**
(State or Other Jurisdiction of Incorporation or Organization)	*(Primary Standard Industrial Classification Code Number)*	*(I.R.S. Employer Identification Number)*

333 Clay Street, Suite 1600
Houston, Texas 77002
(713) 646-4100
(Address, Including Zip Code, and Telephone Number, including Area Code, of Registrant's Principal Executive Offices)

Tim Moore
Vice President and General Counsel
333 Clay Street, Suite 1600
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Copies to:
David P. Oelman
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Approximate date of commencement of proposed sale to the public: From time to time after this Registration Statement becomes effective.

If any of the securities being registered on this form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, check the following box. ý

If this form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If delivery of the prospectus is expected to be made pursuant to Rule 434, please check the following box. o

The registrant hereby amends this registration statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment which specifically states that this registration statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933 or until the registration statement shall become effective on such date as the Securities and Exchange Commission, acting pursuant to said Section 8(a), may determine.

The information in this prospectus is not complete and may be changed. We may not sell these securities until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities and it is not soliciting an offer to buy these securities in any state where the offer or sale is not permitted.

Subject to Completion Dated May 20, 2005

P R O S P E C T U S

19,461,702 Common Units

Plains All American Pipeline, L.P.

Representing Limited Partner Interests

Up to 19,461,702 of our common units may be offered from time to time by the selling unitholders named in this prospectus. The selling unitholders may sell the common units at various times and in various types of transactions, including sales in the open market, sales in negotiated transactions and sales by a combination of methods. We will not receive any proceeds from the sale of common units by the selling unitholders.

Our common units are listed on the New York Stock Exchange under the symbol "PAA."

Limited partnerships are inherently different from corporations. You should carefully consider each of the factors described under "Risk Factors" which begins on page 2 of this prospectus before you make an investment in the securities.

NEITHER THE SECURITIES AND EXCHANGE COMMISION NOR ANY STATE SECURITIES COMMISION HAS APPROVED OR DISAPPROVED OF THESE SECURITIES OR DETERMINED IF THIS PROSPECTUS IS TRUTHFUL OR COMPLETE. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

In connection with certain sales of securities hereunder, a prospectus supplement may accompany this prospectus.

The date of this prospectus is [   ], 2005

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ABOUT THIS PROSPECTUS

This prospectus is part of a registration statement that we filed with the Securities and Exchange Commission, or SEC, using a "shelf' registration process. Under this shelf process, the selling unitholders may sell up to 19,461,702 of our common units. In connection with certain sales of securities hereunder, a prospectus supplement may accompany this prospectus. The prospectus supplement may also add, update or change information contained in this prospectus. Therefore, before you invest in our securities, you should read this prospectus and any attached prospectus supplements.

In this registration statement, the terms "we," "our," "ours," and "us" refer to Plains All American Pipeline, L.P. and its subsidiaries, unless otherwise indicated or the context requires otherwise.

WHO WE ARE

General

We are a publicly traded Delaware limited partnership, formed in 1998 and engaged in interstate and intrastate crude oil transportation, and crude oil gathering, marketing, terminalling and storage, as well as the marketing and storage of liquefied petroleum gas and natural gas related petroleum products. We refer to liquefied petroleum gas and natural gas related petroleum products collectively as "LPG." We have an extensive network of pipeline transportation, storage and gathering assets in key oil producing basins and at major market hubs in the United States and Canada. Our operations can be categorized into two primary business activities: crude oil pipeline transportation operations and gathering, marketing, terminalling and storage operations.

Business Strategy

Our principal business strategy is to capitalize on the regional crude oil supply and demand imbalances that exist in the United States and Canada by combining the strategic location and distinctive capabilities of our transportation and terminalling assets with our extensive marketing and distribution expertise to generate sustainable earnings and cash flow.

We intend to execute our business strategy by:

- increasing and optimizing throughput on our existing pipeline and gathering assets and realizing cost efficiencies through operational improvements;
- utilizing our Cushing Terminal and our other assets to service the needs of refiners and to profit from merchant activities that take advantage of crude oil pricing and quality differentials;
- utilizing assets we have recently acquired along the Gulf Coast and our Cushing Terminal to increase our presence in the importation of foreign crude through Gulf of Mexico receipt facilities to U.S. refiners;
- selectively pursuing strategic and accretive acquisitions of crude oil transportation assets, including pipelines, gathering systems, terminalling and storage facilities and other assets that complement our existing asset base and distribution capabilities;
- optimizing and expanding our Canadian operations and our presence in certain areas of the U.S. to take advantage of anticipated increases in the volume and qualities of crude oil produced in these areas as well as increased foreign crude import activities in the Gulf Coast area; and
- prudently and economically leveraging our asset base, knowledge base and skill sets to participate in energy businesses that are closely related to, or significantly intertwined with, the crude oil business.

To a lesser degree, we also engage in a similar business strategy with respect to the wholesale marketing and storage of LPG, which we began as a result of an acquisition in mid-2001.

RISK FACTORS

Risks Related to Our Business

The level of our profitability is dependent upon an adequate supply of crude oil from fields located offshore and onshore California. Production from these offshore fields has experienced substantial production declines since 1995.

A significant portion of our segment profit is derived from pipeline transportation margins associated with the Santa Ynez and Point Arguello fields located offshore California. We expect that there will continue to be natural production declines from each of these fields as the underlying reservoirs are depleted. We estimate that a 5,000 barrel per day decline in volumes shipped from these fields would result in a decrease in annual pipeline segment profit of approximately $3.2 million. In addition, any significant production disruption from the Santa Ynez field due to production problems, transportation problems or other reasons could have a material adverse effect on our business.

Our trading policies cannot eliminate all price risks. In addition, any non-compliance with our trading policies could result in significant financial losses.

Generally, it is our policy that we establish a margin for crude oil purchased by selling crude oil for physical delivery to third party users, such as independent refiners or major oil companies, or by entering into a future delivery obligation under futures contracts on the NYMEX and over the counter. Through these transactions, we seek to maintain a position that is substantially balanced between purchases, on the one hand, and sales or future delivery obligations, on the other hand. Our policy is generally not to acquire and hold crude oil, futures contracts or derivative products for the purpose of speculating on price changes. These policies and practices cannot, however, eliminate all price risks. For example, any event that disrupts our anticipated physical supply of crude oil could expose us to risk of loss resulting from price changes. Moreover, we are exposed to some risks that are not hedged, including certain basis risks and price risks on certain of our inventory, such as pipeline linefill, which must be maintained in order to transport crude oil on our pipelines. In addition, we engage in a controlled trading program for up to an aggregate of 500,000 barrels of crude oil. Although this activity is monitored independently by our risk management function, it exposes us to price risks within predefined limits and authorizations.

In addition, our trading operations involve the risk of non-compliance with our trading policies. For example, we discovered in November 1999 that our trading policy was violated by one of our former employees, which resulted in aggregate losses of approximately $181.0 million. We have taken steps within our organization to enhance our processes and procedures to detect future unauthorized trading. We cannot assure you, however, that these steps will detect and prevent all violations of our trading policies and procedures, particularly if deception or other intentional misconduct is involved.

If we do not make acquisitions on economically acceptable terms our future growth may be limited.

Our ability to grow is substantially dependent on our ability to make acquisitions that result in an increase in adjusted operating surplus per unit. If we are unable to make such accretive acquisitions either because (i) we are unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (ii) we are unable to raise financing for such acquisitions on economically acceptable terms or (iii) we are outbid by competitors, our future growth will be limited. In particular, competition for midstream assets and businesses has intensified substantially and as a result such assets and businesses have become more costly. As a result, we may not be able to complete the number or size of acquisitions that we have targeted internally or to continue to grow as quickly as we have historically.

Our acquisition strategy requires access to new capital. Tightened capital markets or other factors which increase our cost of capital could impair our ability to grow.

Our business strategy is substantially dependent on acquiring additional assets or operations. We continuously consider and enter into discussions regarding potential acquisitions. These transactions can be effected quickly, may occur at any time and may be significant in size relative to our existing assets and operations. Any material acquisition will require access to capital. Any limitations on our access to capital or increase in the cost of that capital could significantly impair our ability to execute our acquisition strategy. Our ability to maintain our targeted credit profile, including maintaining our credit ratings, could impact our cost of capital as well as our ability to execute our acquisition strategy.

Our acquisition strategy involves risks that may adversely affect our business.

Any acquisition involves potential risks, including:

- performance from the acquired assets and businesses that is below the forecasts we used in evaluating the acquisition;
- a significant increase in our indebtedness and working capital requirements;
- the inability to timely and effectively integrate the operations of recently acquired businesses or assets;
- the incurrence of substantial unforeseen environmental and other liabilities arising out of the acquired businesses or assets, including liabilities arising from the operation of the acquired businesses or assets prior to our acquisition;
- customer or key employee loss from the acquired businesses; and
- the diversion of management's attention from other business concerns.

Any of these factors could adversely affect our ability to achieve anticipated levels of cash flows from our acquisitions, realize other anticipated benefits and our ability to pay distributions or meet our debt service requirements.

The nature of our assets and business could expose us to significant compliance costs and liabilities.

Our operations involving the storage, treatment, processing, and transportation of liquid hydrocarbons including crude oil are subject to stringent federal, state, and local laws and regulations governing the discharge of materials into the environment, and otherwise relating to protection of the environment, operational safety and related matters. Compliance with these laws and regulations increases our overall cost of business, including our capital costs to construct, maintain and upgrade equipment and facilities, or claims for damages to property or persons resulting from our operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial liabilities, the issuance of injunctions that may restrict or prohibit our operations, or claims of damages to property or persons resulting from our operations. The laws and regulations applicable to our operations are subject to change, and we cannot provide any assurance that compliance with current and future laws and regulations will not have a material effect on our results of operations or earnings. A discharge of hazardous liquids into the environment could, to the extent such event is not insured, subject us to substantial expense, including both the cost to comply with applicable laws and regulations and liability to private parties for personal injury or property damage.

The profitability of our pipeline operations depends on the volume of crude oil shipped.

Third party shippers generally do not have long term contractual commitments to ship crude oil on our pipelines. A decision by a shipper to substantially reduce or cease to ship volumes of crude oil on our pipelines could cause a significant decline in our revenues. For example, we estimate that an average 20,000 barrel per day variance in the Basin Pipeline System within the current operating window, equivalent to an approximate 7% volume variance on that system, would change annualized segment profit by approximately $1.7 million. In addition, we estimate that an average 10,000 barrel per day variance on the Capline Pipeline System, equivalent to an approximate 6% volume variance on that system, would change annualized segment profit by approximately $1.4 million.

The success of our business strategy to increase and optimize throughput on our pipeline and gathering assets is dependent upon our securing additional supplies of crude oil.

Our operating results are dependent upon securing additional supplies of crude oil from increased production by oil companies and aggressive lease gathering efforts. The ability of producers to increase production is dependent on the prevailing market price of oil, the exploration and production budgets of the major and independent oil companies, the depletion rate of existing reservoirs, the success of new wells drilled, environmental concerns, regulatory initiatives and other matters beyond our control. There can be no assurance that production of crude oil will rise to sufficient levels to cause an increase in the throughput on our pipeline and gathering assets.

Our operations are dependent upon demand for crude oil by refiners in the Midwest and on the Gulf Coast. Any decrease in this demand could adversely affect our business.

Demand for crude oil is dependent upon the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, governmental regulation or technological advances in fuel economy and energy generation devices, all of which could reduce demand. Demand also depends on the ability and willingness of shippers having access to our transportation assets to satisfy their demand by deliveries through those assets, and any decrease in this demand could adversely affect our business.

We face intense competition in our gathering, marketing, terminalling and storage activities.

Our competitors include other crude oil pipelines, the major integrated oil companies, their marketing affiliates, and independent gatherers, brokers and marketers of widely varying sizes, financial resources and experience. Some of these competitors have capital resources many times greater than ours and control greater supplies of crude oil. We estimate that a $0.01 variance in the average segment profit per barrel would have an approximate $2.4 million annual effect on segment profit.

The profitability of our gathering and marketing activities is generally dependent on the volumes of crude oil we purchase and gather.

To maintain the volumes of crude oil we purchase, we must continue to contract for new supplies of crude oil to offset volumes lost because of natural declines in crude oil production from depleting wells or volumes lost to competitors. Replacement of lost volumes of crude oil is particularly difficult in an environment where production is low and competition to gather available production is intense. Generally, because producers experience inconveniences in switching crude oil purchasers, such as delays in receipt of proceeds while awaiting the preparation of new division orders, producers typically do not change purchasers on the basis of minor variations in price. Thus, we may experience difficulty acquiring crude oil at the wellhead in areas where there are existing relationships between producers and other gatherers and purchasers of crude oil. We estimate that a 15,000 barrel per day decrease in barrels gathered by us would have an approximate $4.3 million per year negative impact on segment profit. This impact is based on a reasonable margin throughout various market conditions. Actual margins vary based on the location of the crude oil, the strength or weakness of the market and the grade or quality of crude oil.

We are exposed to the credit risk of our customers in the ordinary course of our gathering and marketing activities.

There can be no assurance that we have adequately assessed the credit worthiness of our existing or future counterparties or that there will not be an unanticipated deterioration in their credit worthiness, which could have an adverse impact on us.

In those cases in which we provide division order services for crude oil purchased at the wellhead, we may be responsible for distribution of proceeds to all parties. In other cases, we pay all of or a portion of the production proceeds to an operator who distributes these proceeds to the various interest owners. These arrangements expose us to operator credit risk, and there can be no assurance that we will not experience losses in dealings with other parties.

Our pipeline assets are subject to federal, state and provincial regulation.

Our domestic interstate common carrier pipelines are subject to regulation by the Federal Energy Regulatory Commission (FERC) under the Interstate Commerce Act. The Interstate Commerce Act requires that tariff rates for petroleum pipelines be just and reasonable and non-discriminatory. We are also subject to the Pipeline Safety Regulations of the U.S. Department of Transportation. Our intrastate pipeline transportation activities are subject to various state laws and regulations as well as orders of regulatory bodies.

Our Canadian pipeline assets are subject to regulation by the National Energy Board and by provincial agencies. With respect to a pipeline over which it has jurisdiction, each of these Canadian agencies has the power to determine the rates we are allowed to charge for transportation on such pipeline. The extent to which regulatory agencies can override existing transportation contracts has not been fully decided.

Our pipeline systems are dependent upon their interconnections with other crude oil pipelines to reach end markets.

Reduced throughput on these interconnecting pipelines as a result of testing, line repair, reduced operating pressures or other causes could result in reduced throughput on our pipeline systems that would adversely affect our profitability.

Fluctuations in demand can negatively affect our operating results.

Fluctuations in demand for crude oil, such as caused by refinery downtime or shutdown, can have a negative effect on our operating results. Specifically, reduced demand in an area serviced by our transmission systems will negatively affect the throughput on such systems. Although the negative impact may be mitigated or overcome by our ability to capture differentials created by demand fluctuations, this ability is dependent on location and grade of crude oil, and thus is unpredictable.

The terms of our indebtedness may limit our ability to borrow additional funds or capitalize on business opportunities.

As of March 31, 2005, our total outstanding long-term debt was approximately $930 million. Various limitations in our indebtedness may reduce our ability to incur additional debt, to engage in some transactions and to capitalize on business opportunities. Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions.

Changes in currency exchange rates could adversely affect our operating results.

Because we conduct operations in Canada, we are exposed to currency fluctuations and exchange rate risks that may adversely affect our results of operations.

Cash distributions are not guaranteed and may fluctuate with our performance and the establishment of financial reserves.

Because distributions on the common units are dependent on the amount of cash we generate, distributions may fluctuate based on our performance. The actual amount of cash that is available to be distributed each quarter will depend on numerous factors, some of which are beyond our control and the control of the general partner. Cash distributions are dependent primarily on cash flow, including cash flow from financial reserves and working capital borrowings, and not solely on profitability, which is affected by non-cash items. Therefore, cash distributions might be made during periods when we record losses and might not be made during periods when we record profits.

Risks Inherent in an Investment in Plains All American Pipeline

Cost reimbursements due to our general partner may be substantial and will reduce our cash available for distribution to you.

Prior to making any distribution on the common units, we will reimburse our general partner and its affiliates, including officers and directors of the general partner, for all expenses incurred on our behalf. The reimbursement of expenses and the payment of fees could adversely affect our ability to make distributions. The general partner has sole discretion to determine the amount of these expenses. In addition, our general partner and its affiliates may provide us services for which we will be charged reasonable fees as determined by the general partner.

You may not be able to remove our general partner even if you wish to do so.

Our general partner manages and operates Plains All American Pipeline. Unlike the holders of common stock in a corporation, you will have only limited voting rights on matters affecting our business. You will have no right to elect the general partner or the directors of the general partner on an annual or other continuing basis.

In addition, the following provisions of our partnership agreement may discourage a person or group from attempting to remove our general partner or otherwise change our management:

- generally, if a person acquires 20% or more of any class of units then outstanding other than from our general partner or its affiliates, the units owned by such person cannot be voted on any matter; and

- limitations upon the ability of unitholders to call meetings or to acquire information about our operations, as well as other limitations upon the unitholders' ability to influence the manner or direction of management.

As a result of these provisions, the price at which the common units will trade may be lower because of the absence or reduction of a takeover premium in the trading price.

We may issue additional common units without your approval, which would dilute your existing ownership interests.

Our general partner may cause us to issue an unlimited number of common units, without your approval. The issuance of additional common units or other equity securities of equal or senior rank will have the following effects:

- your proportionate ownership interest in Plains All American Pipeline will decrease;

- the amount of cash available for distribution on each unit may decrease;

- the relative voting strength of each previously outstanding unit may be diminished; and

- the market price of the common units may decline.

We may also issue at any time an unlimited number of equity securities ranking junior or senior to the common units without the approval of the unitholders.

Our general partner has a limited call right that may require you to sell your units at an undesirable time or price.

If at any time our general partner and its affiliates own 80% or more of the common units, the general partner will have the right, but not the obligation, which it may assign to any of its affiliates, to acquire all, but not less than all, of the remaining common units held by unaffiliated persons at a price generally equal to the then current market price of the common units. As a result, you may be required to sell your common units at a time when you may not desire to sell them or at a price that is less than the price you would like to receive. You may also incur a tax liability upon a sale of your common units.

You may not have limited liability if a court finds that unitholder actions constitute control of our business.

Under Delaware law, you could be held liable for our obligations to the same extent as a general partner if a court determined that the right of unitholders to remove our general partner or to take other action under our partnership agreement constituted participation in the "control" of our business.

Our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those contractual obligations that are expressly made without recourse to our general partner.

In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that under some circumstances, a unitholder may be liable to us for the amount of a distribution for a period of three years from the date of the distribution.

Conflicts of interest could arise among our general partner and us or the unitholders.

These conflicts may include the following:

- we do not have any employees and we rely solely on employees of the general partner or, in the case of Plains Marketing Canada, employees of PMC (Nova Scotia) Company;

- under our partnership agreement, we reimburse the general partner for the costs of managing and for operating the partnership;

- the amount of cash expenditures, borrowings and reserves in any quarter may affect available cash to pay quarterly distributions to unitholders;

- the general partner tries to avoid being liable for partnership obligations. The general partner is permitted to protect its assets in this manner by our partnership agreement. Under our partnership agreement the general partner would not breach its fiduciary duty by avoiding liability for partnership obligations even if we can obtain more favorable terms without limiting the general partner's liability;

- under our partnership agreement, the general partner may pay its affiliates for any services rendered on terms fair and reasonable to us. The general partner may also enter into additional contracts with any of its affiliates on behalf of us. Agreements or contracts between us and our general partner (and its affiliates) are not the result of arms length negotiations; and

- the general partner would not breach our partnership agreement by exercising its call rights to purchase limited partnership interests or by assigning its call rights to one of its affiliates or to us.

Tax Risks to Common Unitholders

You should read "Tax Considerations" for a more complete discussion of the following expected material federal income tax consequences of owning and disposing of common units.

The IRS could treat us as a corporation for tax purposes, which would substantially reduce the cash available for distribution to you.

The anticipated after-tax benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us.

If we were classified as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate tax rate, which is currently a maximum of 35%. Distributions to you would generally be taxed again to you as corporate distributions, and no income, gains, losses, deductions or credits would flow through to you. Because a tax would be imposed upon us as a corporation, the cash available for distribution to you would be substantially reduced. Treatment of us as a corporation would result in a material reduction in the after-tax return to the unitholders, likely causing a substantial reduction in the value of the common units.

Current law may change so as to cause us to be taxed as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon us as an entity, the cash available for distribution to you would be reduced. Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, then the minimum quarterly distribution and the target distribution levels will be decreased to reflect that impact on us.

A successful IRS contest of the federal income tax positions we take may adversely impact the market for common units.

We have not requested a ruling from the IRS with respect to any matter affecting us. The IRS may adopt positions that differ from the conclusions of our counsel expressed in this registration statement or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain our counsel's conclusions or the positions we take. A court may not concur with our counsel's conclusions or the positions we take. Any contest with the IRS may materially and adversely impact the market for common units and the price at which they trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will be borne by us and directly or indirectly by the unitholders and the general partner.

You may be required to pay taxes even if you do not receive any cash distributions.

You will be required to pay federal income taxes and, in some cases, state and local income taxes on your share of our taxable income even if you do not receive any cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax liability that results from your share of our taxable income.

Tax gain or loss on disposition of common units could be different than expected.

If you sell your common units, you will recognize gain or loss equal to the difference between the amount realized and your tax basis in those common units. Prior distributions in excess of the total net taxable income you were allocated for a common unit, which decreased your tax basis in that common unit, will, in effect, become taxable income to you if the common unit is sold at a price greater than your tax basis in that common unit, even if the price you receive is less than your original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to you. Should the IRS successfully contest some positions we take, you could recognize more gain on the sale of units than would be the case under those positions, without the benefit of decreased income in prior years. Also, if you sell your units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

If you are a tax-exempt entity, a regulated investment company or an individual not residing in the United States, you may have adverse tax consequences from owning common units.

Investment in common units by tax-exempt entities, regulated investment companies or mutual funds and foreign persons raises issues unique to them. For example, virtually all of our income allocated to organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to them. Recent legislation treats net income derived from the ownership of certain publicly traded partnerships (including us) as qualifying income to a regulated investment company. However, this legislation is only effective for taxable years beginning after October 22, 2004, the date of enactment. For taxable years beginning on or before the date of enactment, very little of our income will be qualifying income to a regulated investment company. Distributions to foreign persons will be reduced by withholding taxes at the highest effective U.S. federal income tax rate for individuals, and foreign persons will be required to file federal income tax returns and pay tax on their share of our taxable income.

We treat a purchaser of units as having the same tax benefits without regard to the units purchased. The IRS may challenge this treatment, which could adversely affect the value of the units.

Because we cannot match transferors and transferees of common units, we have adopted depreciation and amortization positions that do not conform with all aspects of the Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from your sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to your tax returns. Please read "Tax Considerations Uniformity of Units" in this prospectus for further discussion of the effect of the depreciation and amortization positions we have adopted.

You will likely be subject to foreign, state and local taxes in jurisdictions where you do not live as a result of an investment in units.

In addition to federal income taxes, you will likely be subject to other taxes, including foreign taxes, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property and in which you do not reside. We own property and conduct business in Canada and in most states in the United States. You may be required to file Canadian federal income tax returns and to pay Canadian federal and provincial income taxes and to file state and local income tax returns and pay state and local income taxes in many or all of the jurisdictions in which we do business or own property. Further, you may be subject to penalties for failure to comply with those requirements. It is your responsibility to file all federal, state, local and foreign tax returns. Our counsel has not rendered an opinion on the foreign, state or local tax consequences of an investment in the common units.

USE OF PROCEEDS

We will not receive any proceeds from the sale of common units by the selling unitholders.

PRICE RANGE OF COMMON UNITS AND DISTRIBUTIONS

As of May 16, 2005, there were 67,914,576 common units outstanding, held by approximately 32,000 holders of record, including common units held in street name. The number of common units outstanding on this date includes the 3,245,700 Class C common units and the 1,307,190 Class B common units that converted in February 2005. The common units are traded on the New York Stock Exchange under the symbol "PAA."

The following table sets forth, for the periods indicated, the high and low sales prices for the common units, as reported on the New York Stock Exchange Composite Transactions Tape, and quarterly cash distributions declared per common unit. The last reported sale price of common units on the New York Stock Exchange on May 16, 2005 was $40.20 per common unit.

	Price Range		
	High	Low	Cash Distributions per Unit[1]
2003			
First Quarter	$ 26.90	$ 24.20	$ 0.5500
Second Quarter	31.48	24.65	0.5500
Third Quarter	32.49	29.10	0.5500
Fourth Quarter	32.82	29.76	0.5625
2004			
First Quarter	$ 35.23	$ 31.18	$ 0.5625
Second Quarter	36.13	27.25	0.5775
Third Quarter	35.98	31.63	0.6000
Fourth Quarter	37.99	34.51	0.6125
2005			
First Quarter	$ 40.98	$ 36.50	$ 0.6375
Second Quarter (through May 16, 2005)	$ 42.77	$ 38.00	(2)

(1) Represents cash distributions attributable to the quarter and paid within 45 days after the quarter.

(2) The distributions attributable to this quarter have not been declared or paid.

SELECTED HISTORICAL FINANCIAL AND OPERATING DATA

We have derived the historical financial information and operating data below from our audited consolidated financial statements as of and for the years ended December 31, 2004, 2003, 2002, 2001, and 2000 and from our unaudited financial statements as of and for the three months ended March 31, 2005 and 2004. The selected financial data should be read in conjunction with the consolidated financial statements, including the notes thereto, and "Management's Discussion and Analysis of Financial Condition and Results of Operations" included in this prospectus.

	Three Months Ended March 31,		Year Ended December 31,				
	2005	2004	2004	2003	2002	2001	2000
			(in millions except per unit data)				
Statement of operations data:							
Revenues[1]	$ 6,638.5	$ 3,804.6	$ 20,975.5	$ 12,589.8	$ 8,384.2	$ 6,868.2	$ 6,641.2
Cost of sales and field operations (excluding LTIP charge)[1]	(6,549.7)	(3,731.2)	(20,641.1)	(12,366.6)	(8,209.9)	(6,720.9)	(6,506.5)
Unauthorized trading losses and related expenses							(7.0)
Inventory valuation adjustment			(2.0)			(5.0)	
LTIP charge operations[2]	(0.3)	(0.6)	(0.9)	(5.7)			
General and administrative expenses (excluding LTIP charge)	(20.2)	(15.5)	(75.8)	(50.0)	(45.7)	(46.6)	(40.8)
LTIP charge general and administrative[2]	(1.9)	(3.7)	(7.0)	(23.1)			
Depreciation and amortization	(19.1)	(13.1)	(67.2)	(46.8)	(34.0)	(24.3)	(24.5)
Total costs and expenses	(6,591.2)	(3,764.1)	(20,794.0)	(12,492.3)	(8,289.6)	(6,796.8)	(6,578.8)
Gain on sale of assets			0.6	0.6		1.0	48.2
Asset impairment			(2.0)				
Operating income	47.3	40.5	180.1	98.2	94.6	72.4	110.6
Interest expense	(14.6)	(9.5)	(46.7)	(35.2)	(29.1)	(29.1)	(28.7)
Interest income and other, net[3]	0.1		(0.3)	(3.6)	(0.2)	0.4	(4.4)
Income from continuing operations before cumulative effect of change in accounting principle[3][4]	$ 32.8	$ 31.0	$ 133.1	$ 59.4	$ 65.3	$ 43.7	$ 77.5
Basic net income per limited partner unit before cumulative effect of change in accounting principle[3][4]	$ 0.43	$ 0.49	$ 1.94	$ 1.01	$ 1.34	$ 1.12	$ 2.13
Diluted net income per limited partner unit before cumulative effect of change in accounting principle[3][4]	$ 0.43	$ 0.49	$ 1.94	$ 1.00	$ 1.34	$ 1.12	$ 2.13
Basic weighted average number of limited partner units outstanding	67.5	58.4	63.3	52.7	45.5	37.5	34.4
Diluted weighted average number of limited partner units outstanding	68.2	59.0	63.3	53.4	45.5	37.5	34.4
Balance sheet data (at end of period):							
Total assets	$ 3,934.2	$ 2,162.0	$ 3,160.4	$ 2,095.6	$ 1,666.6	$ 1,261.2	$ 885.8
Total long-term debt[5]	930.2	687.8	949.0	519.0	509.7	354.7	320.0
Total debt	1,491.2	702.4	1,124.5	646.3	609.0	456.2	321.3
Partners' capital	1,010.6	733.1	1,070.2	746.7	511.6	402.8	214.0
Other data:							
Maintenance capital expenditures	$ 4.0	$ 1.7	$ 11.3	$ 7.6	$ 6.0	$ 3.4	$ 1.8
Net cash provided by (used in) operating activities[6]	(271.8)	133.0	104.0	115.3	185.0	(16.2)	(33.5)

	Three Months Ended March 31,		Year Ended December 31,				
Net cash provided by (used in) investing activities[6]	(61.7)	(155.9)	(651.2)	(272.1)	(374.9)	(263.2)	211.0
Net cash provided by (used in) financing activities	342.6	21.1	554.5	157.2	189.5	279.5	(227.8)
Declared distributions per limited partner unit[7][8][9]	0.61	0.56	2.30	2.19	2.11	1.95	1.83

	Three Months Ended March 31,		Year Ended December 31,				
	2005	2004	2004	2003	2002	2001	2000
Operating Data:							
Volumes (thousands of barrels per day)[10]							
Pipeline segment:							
Tariff activities							
All American	54	55	54	59	65	69	74
Basin	277	275	265	263	93	N/A	N/A
Capline[11]	160	54	123	N/A	N/A	N/A	N/A
West Texas/New Mexico Area Systems[12]	401	209	338	195	110	84	75
Canada	268	240	263	203	187	132	N/A
Other	494	143	369	104	109	60	55
Pipeline margin activities	75	72	74	78	73	61	60
Total	1,729	1,048	1,486	902	637	406	264
Gathering, marketing, terminalling and storage segment:							
Crude oil lease gathering	622	460	589	437	410	348	262
Crude oil bulk purchases	157	122	148	90	68	46	28
Total	779	582	737	527	478	394	290
LPG sales	84	59	48	38	35	19	N/A

(1) Includes buy/sell transactions, see Note 2 "Summary of Significant Accounting Policies" in the "Notes to the Consolidated Financial Statements", which begin at page F-25.

(2) Compensation expense related to our 2005 Long-Term Incentive Plan ("2005 LTIP") and our 1998 Long-Term Incentive Plan ("1998 LTIP"), see "Management 2005 Long-Term Incentive Plan" and "Management 1998 Long-Term Incentive Plan Phantom Units."

(3) The 2000 period includes $15.1 million related to losses on the early extinguishment of debt previously classified as an extraordinary item. Effective with our adoption of Statement of Financial Accounting Standards ("SFAS") 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections" in January 2003, such items are now shown as impacting income from continuing operations. As a result of this reclassification, basic and diluted net income per limited partner unit before cumulative effect of change in accounting principle for 2000 was reduced by $0.44. In addition, effective with the issuance of the Emerging Issues Task Force Issue No. 03-06 ("EITF 03-06"), "Participating Securities and the Two Class Method under FASB Statement No. 128," the 2000 amount was further reduced by $0.07.

(4) Income from continuing operations before cumulative effect of change in accounting principle pro forma for the impact of our January 1, 2004 change in our method of accounting for pipeline linefill in third party assets would have been $61.4 million, $64.8 million, $38.4 million and $78.2 million for each of the four years ended December 31, 2003, respectively. In addition, basic net income per limited partner unit before cumulative effect of change in accounting principle would have been $1.05 ($1.04 diluted), $1.33 ($1.33 diluted), $0.97 ($0.97 diluted) and $2.15 ($2.15 diluted) for each of the four years ended December 31, 2003, respectively.

(5) Includes current maturities of long-term debt of $9.0 million and $3.0 million at December 31, 2002 and 2001, respectively, classified as long-term because of our ability and intent to refinance these amounts under our long-term revolving credit facilities.

(6) In conjunction with the change in accounting principle we adopted as of January 1, 2004, we have reclassified cash flows for the years 2003 and prior associated with purchases and sales of linefill on assets that we own as cash flows from investing activities instead of the historical classification as cash flows from operating activities.

(7) Distributions represent those declared and paid in the applicable period.

(8) No distributions were declared or paid on subordinated units in the first quarter of 2000. A distribution of $0.45 per unit was declared and paid to holders of common units in that period.

(9) Our general partner is entitled to receive 2% proportional distributions and also incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. See Note 6 "Partners' Capital and Distributions" in the "Notes to the Consolidated Financial Statements", which begin at page F-25.

(10) Volumes associated with acquisitions represent total volumes transported for the number of days we actually owned the assets divided by the number of days in the period.

(11) Capline volumes averaged approximately 160,000 barrels per day for March 2004, which was the only month during the first quarter of 2004 in which we owned the system.

(12) The aggregate of ten systems in the West Texas/New Mexico area.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Introduction

The following discussion is intended to provide investors with an understanding of our financial condition and results of our operations for the years ended December 31, 2004, 2003 and 2002, as well as the three month periods ended March 31, 2005 and 2004, and should be read in conjunction with our historical consolidated financial statements and accompanying notes.

Our discussion and analysis includes the following:

- Executive Summary
- Acquisitions
- Critical Accounting Policies and Estimates
- Recent Accounting Pronouncements and Change in Accounting Principle
- Results of Operations
- Outlook
- Liquidity and Capital Resources
- Off-Balance Sheet Arrangements
- Risk Factors Related to Our Business

Executive Summary

Company Overview

Plains All American Pipeline, L.P. is a Delaware limited partnership formed in September of 1998. Our operations are conducted directly and indirectly through our operating subsidiaries, Plains Marketing, L.P., Plains Pipeline, L.P. and Plains Marketing Canada, L.P. We are engaged in interstate and intrastate crude oil transportation, and crude oil gathering, marketing, terminalling and storage, as well as the marketing and storage of liquefied petroleum gas and other petroleum products. We refer to liquified petroleum gas and other petroleum products collectively as "LPG." We have an extensive network of pipeline transportation, terminalling, storage and gathering assets in key oil producing basins and at major market hubs in the United States and Canada.

We are one of the largest midstream crude oil companies in North America. As of December 31, 2004, we owned approximately 15,000 miles of active crude oil pipelines, approximately 37 million barrels of active terminalling and storage capacity and over 400 transport trucks. Currently, we handle an average of over 2.9 million barrels per day of physical crude oil through our extensive network of assets located in major oil producing regions of the United States and Canada. Our operations consist of two operating segments: (i) pipeline operations ("Pipeline Operations") and (ii) gathering, marketing, terminalling and storage operations ("GMT&S"). Through our pipeline segment, we engage in interstate and intrastate crude oil pipeline transportation and certain related margin activities. Through our GMT&S segment, we engage in purchases and resales of crude oil and LPG at various points along the distribution chain and we operate certain terminalling and storage assets.

Years Ended December 31, 2004, 2003 and 2002

Overview of Operating Results and Significant Activities

During 2004, we recognized net income and earnings per limited partner unit of $130.0 million and $1.89, respectively, both of which were substantial increases over 2003 and 2002. The results for 2004 as compared to the two previous years include significant contributions from acquisitions completed during 2003 and 2004.

The following significant activities impacted our operations, operating results or our financial position during 2004:

Effective April 1, 2004, we acquired all of the North American crude oil and pipeline operations of Link Energy LLC ("Link") for approximately $332 million. Additionally, effective March 1, 2004, we completed the acquisition of all of Shell Pipeline Company LP's interests in two entities for approximately $158.5 million (including a $15.8 million deposit paid in December 2003). The principal assets of the Shell entities are: (i) an approximate 22% undivided joint interest in the Capline Pipeline System, and (ii) an approximate 76% undivided joint interest in the Capwood Pipeline System.

We maintained the relative strength of our overall capital structure and maintained substantial liquidity through a series of equity issuances and senior notes issuances. We also entered into new credit facilities which expanded and extended the size and maturity of our prior facilities. See " Liquidity and Capital Resources."

We realized year over year growth in segment profit from both our pipeline operations segment and our GMT&S segment. This growth was primarily driven by (i) the impact of the current year acquisitions subsequent to their acquisition during 2004, (ii) inclusion of a full year contribution from those assets that we acquired during 2003, and (iii) the positive results, in relatively volatile market conditions, of our counter-cyclically balanced activities in our GMT&S segment.

We changed our method of accounting for pipeline linefill in third party assets resulting in a cumulative effect of change in accounting principle charge of $3.1 million. See " Recent Accounting Pronouncements and Change in Accounting Principle."

Under generally accepted accounting principles, we are required to recognize an expense when vesting of units under our 1998 Long-Term Incentive Plan ("1998 LTIP") becomes probable as determined by management. Our results of operations for 2004 include a charge of $7.9 million.

Recognized a foreign exchange gain of $5.0 million related to the impact of changes in the Canadian dollar to U.S. dollar exchange rate on a net U.S. dollar denominated liability of our Canadian subsidiary. This is primarily attributable to our LPG business, a substantial amount of which is transacted in U.S. Dollars.

Recognized a lower-of-cost-or-market inventory charge of approximately $2.0 million related to a valuation adjustment on our LPG inventory. This charge is linked to the foreign exchange gain mentioned above, and is effectively a partial reversal of that gain. This is primarily because of a stronger Canadian dollar relative to the U.S. dollar at the date of measurement compared to at the time of purchase.

Recognized a non-cash gain of approximately $1.0 million resulting from the mark-to-market of open derivative instruments pursuant to Statement of Financial Accounting Standard No. 133, as amended ("SFAS 133").

Recognized a non-cash charge of approximately $2.0 million associated with taking our pipeline system in the Illinois Basin out of service. This pipeline did not support spending the capital

necessary to continue service and we shifted the majority of the gathering and transport activities to trucks. As a result, we were able to maintain most of our margins.

Prospects for the Future

We believe we have access to equity and debt capital and that we are well situated to optimize our position in and around our existing assets and to expand our asset base by continuing to consolidate, rationalize and optimize the North American crude oil infrastructure. We have deliberately configured our assets to provide a counter-cyclical balance between our gathering and marketing activities and our terminalling and storage activities. We believe the combination of these balanced activities adds stability to the portion of our business that is highly cyclical, and with our relatively stable, fee-based pipeline assets, enables us to generate stable financial results.

During 2004 we strengthened our business by expanding our asset base through acquisitions and internal growth projects. We operate in a mature industry and believe that our primary source of growth will come from acquisitions, and we believe that there are opportunities for acquisitions. We will continue to pursue the purchase of midstream crude oil assets, and we will also continue to initiate projects designed to optimize crude oil flows in the areas in which we operate. We believe the outlook is positive for, and have a strategic initiative of increasing our participation in, the importing of foreign crude oil, primarily through building a meaningful asset presence to enable us to receive foreign crude oil via the Gulf Coast. We also believe there are opportunities for us to grow our LPG business. In addition, we believe we can, and will pursue opportunities to, leverage our assets, business model, knowledge and expertise into investments in businesses complementary to our crude oil and LPG activities. Although we believe that we are well situated in the North American crude oil infrastructure, we face various operational, regulatory and financial challenges that may impact our ability to execute our strategy as planned. See "Risk Factors Risks Related to Our Business" for further discussion of these items. We can give no assurance that our current or future acquisition efforts will be successful or that any such acquisition will be completed on terms considered favorable to us.

Acquisitions

We completed a number of acquisitions in 2004, 2003 and 2002 that have impacted the results of operations and liquidity discussed herein. The following acquisitions were accounted for, and the purchase price was allocated, in accordance with the purchase method of accounting. We adopted SFAS No. 141, "Business Combinations" in 2001 and followed the provisions of that statement for all business combinations initiated after June 30, 2001. Our ongoing acquisition activity is discussed further in "Liquidity and Capital Resources" below.

2004 Acquisitions

In 2004, we completed several acquisitions for aggregate consideration of approximately $549.5 million. The aggregate consideration includes cash paid, estimated transaction costs and assumed liabilities and net working capital items. The following table summarizes our 2004 acquisitions, and a description of each of these follows the table:

Acquisition	Effective Date	Acquisition Cost		Operating Segment
Capline and Capwood Pipeline System	03/01/04	$	158.5	Pipeline
Link Energy LLC	04/01/04		332.3	Pipeline/GMT&S
Cal Ven Pipeline System	05/01/04		19.0	Pipeline
Schaefferstown Propane Storage Facility	08/25/04		32.0	GMT&S
Other	various		7.7	GMT&S
Total 2004 Acquisitions		$	549.5	

Capline and Capwood Pipeline Systems. In March 2004, we completed the acquisition of all of Shell Pipeline Company LP's interests in two entities for approximately $158.0 million in cash (including a $15.8 million deposit paid in December 2003) and approximately $0.5 million of transaction and other costs. In December 2003, subsequent to the announcement of the acquisition and in anticipation of closing, we issued approximately 2.8 million common units for net proceeds of approximately $88.4 million, after paying approximately $4.1 million of transaction costs. The proceeds from this issuance were used to pay down the outstanding balances under our revolving credit facility. At closing, the cash portion of this acquisition was funded from cash on hand and borrowings under our revolving credit facility.

The principal assets of the entities are: (i) an approximate 22% undivided joint interest in the Capline Pipeline System, and (ii) an approximate 76% undivided joint interest in the Capwood Pipeline System. The Capline Pipeline System is a 633-mile, 40-inch mainline crude oil pipeline originating in St. James, Louisiana, and terminating in Patoka, Illinois. The Capwood Pipeline System is a 57-mile, 20-inch mainline crude oil pipeline originating in Patoka, Illinois, and terminating in Wood River, Illinois. The results of operations and assets from this acquisition (the "Capline acquisition") have been included in our consolidated financial statements and in our pipeline operations segment since March 1, 2004. These pipelines provide one of the primary transportation routes for crude oil shipped into the Midwestern U.S. and delivered to several refineries and other pipelines.

The purchase price was allocated as follows (in millions):

Crude oil pipelines and facilities	$	151.4
Crude oil storage and terminal facilities		5.7
Land		1.3
Office equipment and other		0.1
	$	158.5

Link Energy LLC. On April 1, 2004, we completed the acquisition of all of the North American crude oil and pipeline operations of Link for approximately $332 million, including $268 million of cash and approximately $64 million of net liabilities assumed and acquisition related costs. The Link crude oil business consists of approximately 7,000 miles of active crude oil pipeline and gathering systems, over 10 million barrels of active crude oil storage capacity, a fleet of approximately 200 owned or leased trucks and approximately 2 million barrels of crude oil linefill and working inventory. The Link assets complement our assets in West Texas and along the Gulf Coast and allow us to expand our presence in the Rocky Mountain and Oklahoma/Kansas regions. The results of operations and assets from this acquisition (the "Link acquisition") have been included in our consolidated financial statements and both our pipeline operations and GMT&S operations segments since April 1, 2004.

The purchase price was allocated as follows and includes goodwill primarily related to Link's gathering and marketing business (in millions):

Cash paid for acquisition[1]	$	268.0
Fair value of net liabilities assumed:		
Accounts receivable[2]		409.4
Other current assets		1.8
Accounts payable and accrued liabilities[2]		(459.6)
Other current liabilities		(8.5)
Other long-term liabilities		(7.4)
Total net liabilities assumed		(64.3)
Total purchase price	$	332.3
Purchase price allocation		
Property and equipment	$	260.2
Inventory		3.4
Linefill		55.4
Inventory in third party assets		8.1
Goodwill		5.0
Other long term assets		0.2
Total	$	332.3

(1) Cash paid does not include the subsequent payment of various transaction and other acquisition related costs.

(2) Accounts receivable and accounts payable are gross and do not reflect the adjustment of approximately $250 million to net settle, based on contractual agreements with our counterparties.

The total purchase price includes (i) $9.4 million in transaction costs, (ii) approximately $7.4 million related to a plan to involuntarily terminate and relocate employees in conjunction with the acquisition, and (iii) approximately $11.0 million related to costs to terminate a contract assumed in the acquisition. These activities are substantially complete and the majority of the related costs have been incurred as of December 31, 2004. In addition, we anticipate making capital expenditures of approximately $28.0 million ($18.0 million in 2005) to upgrade certain of the assets and comply with certain regulatory requirements.

The acquisition was initially funded with cash on hand and borrowings under our existing credit facilities as well as under a new $200 million, 364-day credit facility. In connection with the acquisition, on April 15, 2004, we completed the private placement of 3,245,700 Class C common units to a group of institutional investors. During the third quarter of 2004, we completed a public offering of common units and the sale of unsecured senior notes. A portion of the proceeds from these transactions was used to retire the $200 million, 364-day credit facility.

Cal Ven Pipeline System. On May 7, 2004 we completed the acquisition of the Cal Ven Pipeline System from Cal Ven Limited, a subsidiary of Unocal Canada Limited. The total purchase price was approximately $19 million, including transaction costs. The transaction was funded through a combination of cash on hand and borrowings under our revolving credit facilities. The Cal Ven Pipeline System includes approximately 195 miles of 8-inch and 10-inch gathering and mainline crude oil pipelines. The system is located in northern Alberta and delivers crude oil into the Rainbow Pipeline System. The Rainbow Pipeline System then transports the crude south to the Edmonton market, where it can be used in local refineries or shipped on connecting pipelines to the U.S. market. The results of

operations and assets from this acquisition have been included in our consolidated financial statements and our pipeline operations segment since May 1, 2004.

Schaefferstown Propane Storage Facility. In August 2004, we completed the acquisition of the Schaefferstown Propane Storage Facility from Koch Hydrocarbon, L.P. The total purchase price was approximately $32 million, including transaction costs. In connection with the transaction, we also acquired an additional $14.2 million of inventory. The transaction was funded through a combination of cash on hand and borrowings under our revolving credit facilities. The results of operations and assets from this acquisition have been included in our consolidated financial statements and our gathering, marketing, terminalling and storage operations segment since August 25, 2004.

2003 Acquisitions

During 2003, we completed ten acquisitions for aggregate consideration of approximately $159.5 million. The aggregate consideration includes cash paid, estimated transaction costs, assumed liabilities and estimated near-term capital costs. The acquisitions were initially financed with borrowings under our credit facilities, which were subsequently repaid with a portion of the proceeds from our equity issuances and the issuance of senior notes. See " Liquidity and Capital Resources." The businesses acquired during 2003 impacted our results of operations commencing on the effective date of each acquisition as indicated below. These acquisitions included mainline crude oil pipelines, crude oil gathering lines, terminal and storage facilities, and an underground LPG storage facility. With the exception of $0.5 million that was allocated to goodwill and other intangible assets and $4.7 million associated with crude oil linefill and working inventory, the remaining aggregate purchase price was allocated to property and equipment. The following table details our 2003 acquisitions (in millions):

Acquisition	**Effective Date**	**Acquisition Price**		**Operating Segment**
Red River Pipeline System	02/01/03	$	19.4	Pipeline
Iatan Gathering System	03/01/03		24.3	Pipeline
Mesa Pipeline Facility	05/05/03		2.9	Pipeline
South Louisiana Assets[1]	06/01/03		13.4	Pipeline/G,M,T,&S
Alto Storage Facility	06/01/03		8.5	G,M,T&S
Iraan to Midland Pipeline System	06/30/03		17.6	Pipeline
ArkLaTex Pipeline System	10/01/03		21.3	Pipeline
South Saskatchewan Pipeline System	11/01/03		47.7	Pipeline
Atchafalaya Pipeline System[2]	12/01/03		4.4	Pipeline
Total 2003 Acquisitions		$	159.5	

(1) Includes a 33.3% interest in Atchafalaya Pipeline L.L.C.

(2) Includes two acquisitions each for 33.3% interests in Atchafalaya Pipeline L.L.C.

2002 Acquisitions

Shell West Texas Assets. On August 1, 2002, we acquired interests in approximately 2,000 miles of gathering and mainline crude oil pipelines and approximately 9.0 million barrels (net to our interest) of above ground crude oil terminalling and storage assets in West Texas from Shell Pipeline Company LP and Equilon Enterprises LLC (the "Shell acquisition") for approximately $324 million. The primary assets included in the transaction are interests in the Basin Pipeline System, the Permian Basin Gathering System and the Rancho Pipeline System. The entire purchase price was allocated to property and equipment.

The acquired assets are primarily fee-based mainline crude oil pipeline transportation assets that gather crude oil in the Permian Basin and transport the crude oil to major market locations in the Mid-Continent and Gulf Coast regions. The Permian Basin has long been one of the most stable crude oil producing regions in the United States, dating back to the 1930s. The acquired assets complement our existing asset infrastructure in West Texas and represent a transportation link to Cushing, Oklahoma, where we provide storage and terminalling services. The Rancho Pipeline System was taken out of service in March 2003, pursuant to the operating agreement. See "Business Dispositions Shutdown and Sale of Rancho Pipeline System."

Other 2002 Acquisitions. During February and March of 2002, we completed two other acquisitions for aggregate consideration totaling $15.9 million, with effective dates of February 1, 2002 and March 31, 2002, respectively. These acquisitions include an equity interest in a crude oil pipeline company and crude oil gathering and marketing assets.

Critical Accounting Policies and Estimates

Our critical accounting policies are discussed in Note 2 to the Consolidated Financial Statements. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, as well as the disclosure of contingent assets and liabilities, at the date of the financial statements. Such estimates and assumptions also affect the reported amounts of revenues and expenses during the reporting period. Although we believe these estimates are reasonable, actual results could differ from these estimates. The critical accounting policies that we have identified are discussed below.

Purchase and Sales Accruals. We routinely make accruals based on estimates for certain components of our revenues and cost of sales due to the timing of compiling billing information, receiving third-party information and reconciling our records with those of third parties. Where applicable, these accruals are based on nominated volumes expected to be purchased, transported and subsequently sold. Uncertainties involved in these estimates include levels of production at the wellhead, access to certain qualities of crude oil, pipeline capacities and delivery times, utilization of truck fleets to transport volumes to their destinations, weather, market conditions and other forces beyond our control. These estimates are generally associated with a portion of the last month of each reporting period. We currently estimate that less than 2% of total annual revenues and cost of sales are recorded using estimates and less than 5% of total quarterly revenues and cost of sales are recorded using estimates. Accordingly, a variance from this estimate of 10% would impact the respective line items by less than 1% on both an annual and quarterly basis. Although the resolution of these uncertainties has not historically had a material impact on our reported results of operations or financial condition, because of the high volume, low margin nature of our business, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts. Variances from estimates are reflected in the period actual results become known, typically in the month following the estimate.

Mark-to-Market Accrual. In situations where we are required to make mark-to-market estimates pursuant to SFAS 133, the estimates of gains or losses at a particular period end do not reflect the end results of particular transactions, and will most likely not reflect the actual gain or loss at the conclusion of a transaction. We reflect estimates for these items based on our internal records and information from third parties. A portion of the estimates we use are based on internal models or models of third parties because they are not quoted on a national market. Additionally, values may vary among different models due to a difference in assumptions applied such as the estimate of prevailing market prices, volatility, correlations and other factors and may not be reflective of the price at which they can be settled due to the lack of a liquid market. Less than 1% of total revenues are based on estimates derived from these models. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts.

Contingent Liability Accruals. We accrue reserves for contingent liabilities including, but not limited to, environmental remediation, insurance claims, asset retirement obligations and potential legal claims. Accruals are made when our assessment indicates that it is probable that a liability has occurred and the amount of liability can be reasonably estimated. Our estimates are based on all known facts at the time and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment, costs of medical care associated with worker's compensation and employee health insurance claims, and the possibility of existing legal claims giving rise to additional claims. Our estimates for contingent liability accruals are increased or decreased as additional information is obtained or resolution is achieved. A variance of 10% in our aggregate estimate for the contingent liabilities discussed above would have an approximate $2.3 million impact on earnings. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts.

Fair Value of Assets and Liabilities Acquired and Identification of Associated Goodwill and Intangible Assets. In conjunction with each acquisition, we must allocate the cost of the acquired entity to the assets and liabilities assumed based on their estimated fair values at the date of acquisition. We also estimate the amount of transaction costs that will be incurred in connection with each acquisition. As additional information becomes available, we may adjust the original estimates within a short time period subsequent to the acquisition. In addition, in conjunction with the adoption of SFAS 141, we are required to recognize intangible assets separately from goodwill. Goodwill and intangible assets with indefinite lives are not amortized but instead are periodically assessed for impairment. The impairment testing entails estimating future net cash flows relating to the asset, based on management's estimate of market conditions including pricing, demand, competition, operating costs and other factors. Intangible assets with finite lives are amortized over the estimated useful life determined by management. Determining the fair value of assets and liabilities acquired, as well as intangible assets that relate to such items as customer relationships, contracts, and industry expertise involves professional judgment and is ultimately based on acquisition models and management's assessment of the value of the assets acquired and, to the extent available, third party assessments. Uncertainties associated with these estimates include changes in production decline rates, production interruptions, fluctuations in refinery capacity or product slates, economic obsolescence factors in the area and potential future sources of cash flow. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts.

Recent Accounting Pronouncements and Change in Accounting Principle

Recent Accounting Pronouncements

Buy/sell transactions. The Emerging Issues Task Force ("EITF") is currently considering Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty," ("EITF No. 04-13"), which relates to buy/sell transactions. The issues to be addressed by the EITF are i) under what circumstances should two or more transactions with the same counterparty be viewed as a single nonmonetary transaction within the scope of APB No. 29; and ii) if nonmonetary transactions within the scope of APB No. 29 involve inventory, are there any circumstances under which the transactions should be recognized at fair value.

Buy/sell transactions are contractual arrangements in which we agree to buy a specific quantity and quality of crude oil or LPG to be delivered at a specific location while simultaneously agreeing to sell a specified quantity and quality of crude oil or LPG at a different location, usually with the same counterparty. These arrangements are generally designed to increase our margin through a variety of methods, including reducing our transportation or storage costs or acquiring a grade of crude oil that more closely matches our physical delivery requirement to one of our other customers. The value difference between purchases and sales is referred to as margin and is primarily due to grade, quality or location differentials. All buy/sell transactions result in us making or receiving physical delivery of the product, involve the attendant risks and rewards of ownership, including title transfer, assumption of environmental risk, transportation scheduling, credit risk and counterparty nonperformance risk, and such transactions are settled in cash similar to all other purchases and sales. Accordingly, such transactions are recorded in both revenues and purchases as separate sales and purchase transactions on a "gross" basis.

We believe that buy/sell transactions are monetary in nature and thus outside the scope of APB Opinion No. 29, "Accounting for Nonmonetary Transactions" ("APB No. 29"). Additionally, we have evaluated EITF No. 99-19, "Reporting Revenue Gross as a Principal versus Net as an Agent" ("EITF No. 99-19") and, based on that evaluation, we believe that recording these transactions on a gross basis is appropriate. If the EITF were to determine that these transactions should be accounted for as monetary transactions on a gross basis, no change in our accounting policy for buy/sell transactions would be necessary. If the EITF were to determine that these transactions should be accounted for as nonmonetary transactions qualifying for fair value recognition and require a net presentation of such transactions, the amounts of revenues and purchases associated with buy/sell transactions would be netted in our consolidated statement of operations, but there would be no effect on operating income, net income or cash flows from operating activities. If the EITF were to determine that these transactions should be accounted for as nonmonetary transactions not qualifying for fair value recognition, these amounts of revenues and purchases would be netted in our consolidated statement of operations and there could be an impact on operating income and net income related to the timing of the ultimate sale of product purchased in the "buy" side of the buy/sell transaction. However, we do not believe any impact on operating income, net income or cash flows from operating activities would be material.

Earnings per Unit. In March 2004, the Emerging Issues Task Force issued Issue No. 03-06 ("EITF 03-06"), "Participating Securities and the Two-Class Method under FASB Statement No. 128." EITF 03-06 addresses a number of questions regarding the computation of earnings per share by companies that have issued securities, other than common stock, that contractually entitle the holder to participate in dividends and earnings of the company when, and if, it declares dividends on its common stock. The issue also provides further guidance in applying the two-class method of calculating earnings per share, clarifying what constitutes a participating security and how to apply the two-class method of computing earnings per share once it is determined that a security is participating, including how to allocate undistributed earnings to such a security. EITF 03-06 was effective for fiscal periods beginning after March 31, 2004. The adoption of EITF 03-06 may have an impact on earnings per limited partner unit in future periods if net income exceeds distributions or if other participating securities are issued. The effect of applying EITF 03-06 on prior periods was not material except for the year ended December 31, 2000, which has been restated as shown below.

Basic and Diluted Income Before Extraordinary Item and Cumulative Effect of Change in Accounting Principle per Limited Partner Unit:

	For the Year Ended December 31, 2000	
Prior to the adoption of SFAS 145[1] or EITF 03-06	$	2.64
After the adoption of SFAS 145 but prior to the adoption of EITF 03-06	$	2.20
After the adoption of both SFAS 145 and EITF 03-06	$	2.13

(1) SFAS 145 "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13 and Technical Corrections."

Change in Accounting Principle

During the second quarter of 2004, we changed our method of accounting for pipeline linefill in third party assets. Historically, we have viewed pipeline linefill, whether in our assets or third party assets, as having long-term characteristics rather than characteristics typically associated with the short-term classification of operating inventory. Therefore, previously we have not included linefill barrels in the same average costing calculation as our operating inventory, but instead have carried linefill at historical cost. Following this change in accounting principle, the linefill in third party assets that we have historically classified as a portion of "Pipeline Linefill" on the face of the balance sheet (a long-term asset) and carried at historical cost, is included in "Inventory" (a current asset) in determining the average cost of operating inventory and applying the lower of cost or market analysis. At the end of each period, we reclassify the linefill in third party assets not expected to be liquidated within the succeeding twelve months out of "Inventory" (a current asset), at average cost, and into "Inventory in Third Party Assets" (a long-term asset), which is now reflected as a separate line item within other assets on the consolidated balance sheet.

This change in accounting principle was effective January 1, 2004 and is reflected in our consolidated statement of operations for the year ended December 31, 2004 and our consolidated balance sheet as of December 31, 2004. The cumulative effect of this change in accounting principle as of January 1, 2004, is a charge of approximately $3.1 million, representing a reduction in Inventory of approximately $1.7 million, a reduction in Pipeline Linefill of approximately $30.3 million and an increase in Inventory in Third Party Assets of $28.9 million. The pro forma impact for the periods ended December 31, 2003 and 2002 is detailed below:

	Reported Year Ended December 31,				Impact of Change in Accounting Principle Year Ended December 31,				Pro Forma Year Ended December 31,			
	2003		2002		2003		2002		2003		2002	
Net income	$	59.5	$	65.3	$	2.0	$	(0.1)	$	61.5	$	65.2
Basic income per limited partner unit	$	1.01	$	1.34	$	0.04	$		$	1.05	$	1.34
Diluted income per limited partner unit	$	1.00	$	1.34	$	0.04	$		$	1.04	$	1.34

In conjunction with this change in accounting principle, we have classified cash flows associated with purchases and sales of linefill on assets that we own as cash flows from investing activities instead of the historical classification of cash flows from operating activities. Accordingly, our statement of cash flows for the years ended December 31, 2003 and 2002 has been revised to reclassify the cash paid for linefill in assets owned from operating activities to investing activities. As a result of this change in classification, net cash provided by operating activities for the years ended December 31, 2003 and 2002 increased to $115.3 million from $68.5 million and to $185.0 million from $173.9 million, respectively.

Net cash used in investing activities for the years ended December 31, 2003 and 2002 increased to $272.1 million from $225.3 million and $374.8 million from $363.8 million, respectively.

Results of Operations

Analysis of Operating Segments

Our operations consist of two operating segments: (i) Pipeline Operations and (ii) GMT&S Operations. Through our pipeline segment, we engage in interstate and intrastate crude oil pipeline transportation and certain related margin activities. Through our GMT&S segment, we engage in purchases and resales of crude oil and LPG at various points along the distribution chain and we operate certain terminalling and storage assets. We believe that the combination of our terminalling and storage activities and gathering and marketing activities provides a counter-cyclical balance that has a stabilizing effect on our results of operations and cash flow. In a contango market (oil prices for future deliveries are higher than for current deliveries), we use our tankage to improve our gathering margins by storing crude oil we have purchased at lower prices in the current month for delivery at higher prices in future months. In a backwardated market (oil prices for future deliveries are lower than for current deliveries), we use less storage capacity, but increased marketing margins (premiums for prompt delivery) provide an offset to this reduced cash flow.

We evaluate segment performance based on segment profit and maintenance capital. We define segment profit as revenues less (i) purchases, (ii) field operating costs and (iii) segment general and administrative ("G&A") expenses. Each of the items above excludes depreciation and amortization. As a master limited partnership, we make quarterly distributions of our "available cash" (as defined in our partnership agreement) to our unitholders. Therefore, we look at each period's earnings before non-cash depreciation and amortization as an important measure of segment performance. The exclusion of depreciation and amortization expense could be viewed as limiting the usefulness of segment profit as a performance measure because it does not account in current periods for the implied reduction in value of our capital assets, such as crude oil pipelines and facilities, caused by aging and wear and tear. Management compensates for this limitation by recognizing that depreciation and amortization are largely offset by repair and maintenance costs, which keep the actual value of our principal fixed assets from declining. These maintenance costs are a component of field operating costs included in segment profit or in maintenance capital, depending on the nature of the cost. Maintenance capital consists of capital expenditures required either to maintain the existing operating capacity of partially or fully depreciated assets or to extend their useful lives. Capital expenditures made to expand our existing capacity, whether through construction or acquisition, are not considered maintenance capital expenditures. Repair and maintenance expenditures associated with existing assets that do not extend the useful life or expand the operating capacity are charged to expense as incurred. See Note 14 "Operating Segments" in the "Notes to the Consolidated Financial Statements" for a reconciliation of segment profit to consolidated income before cumulative effect of change in accounting principle. The following table reflects our results of operations and maintenance capital for each segment.

	Pipeline Operations	GMT&S Operations
	(in millions)	
Year Ended December 31, 2004[1]		
Revenues	$ 874.9	$ 20,223.5
Purchases	(554.6)	(19,992.8)
Field operating costs (excluding LTIP charge)	(121.1)	(97.5)
LTIP charge operations	(0.1)	(0.8)
Segment G&A expenses (excluding LTIP charge)[2]	(38.1)	(37.7)
LTIP charge general and administrative	(3.8)	(3.2)
Segment profit	$ 157.2	$ 91.5
Noncash SFAS 133 impact[3]	$	$ 1.0
Maintenance capital	$ 8.3	$ 3.0
Year Ended December 31, 2003[1]		
Revenues	$ 658.6	$ 11,985.6
Purchases	(487.1)	(11,799.8)
Field operating costs (excluding LTIP charge)	(60.9)	(73.3)
LTIP charge operations	(1.5)	(4.3)
Segment G&A expenses (excluding LTIP charge)[2]	(18.3)	(31.6)
LTIP charge general and administrative	(9.5)	(13.5)
Segment profit	$ 81.3	$ 63.1
Noncash SFAS 133 impact[3]	$	$ 0.4
Maintenance capital	$ 6.4	$ 1.2
Year Ended December 31, 2002[1]		
Revenues	$ 486.2	$ 7,921.8
Purchases	(362.2)	(7,765.1)
Field operating costs	(40.1)	(66.3)
Segment G&A expenses[2]	(13.2)	(31.5)
Segment Profit	$ 70.7	$ 58.9
Noncash SFAS 133 impact[3]	$	$ 0.3
Maintenance capital	$ 3.4	$ 2.6

(1)

Revenues and purchases include intersegment amounts.

(2) Segment G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on the business activities that existed at that time. The proportional allocations by segment require judgment by management and will continue to be based on the business activities that exist during each period.

(3) Amounts related to SFAS 133 are included in revenues and impact segment profit.

Pipeline Operations

As of December 31, 2004, we owned approximately 15,000 miles (of which approximately 13,000 miles are included in our pipeline segment) of active gathering and mainline crude oil pipelines located throughout the United States and Canada. Our activities from pipeline operations generally consist of transporting volumes of crude oil for a fee and third party leases of pipeline capacity (collectively referred to as "tariff activities"), as well as barrel exchanges and buy/sell arrangements (collectively referred to as "pipeline margin activities"). In connection with certain of our merchant activities conducted under our gathering and marketing business, we are also shippers on certain of our own pipelines. These transactions are conducted at published tariff rates and eliminated in consolidation. Tariffs and other fees on our pipeline systems vary by receipt point and delivery point. The segment profit generated by our tariff and other fee-related activities depends on the volumes transported on the pipeline and the level of the tariff and other fees charged as well as the fixed and variable field costs of operating the pipeline. Segment profit from our pipeline capacity leases, barrel exchanges and buy/sell arrangements generally reflect a negotiated amount.

The following table sets forth our operating results from our Pipeline Operations segment for the periods indicated:

	Year Ended December 31,		
	2004	**2003**	**2002**
		(in millions)	
Operating Results[1]			
Revenues			
Tariff activities	$ 299.7	$ 153.3	$ 103.7
Pipeline margin activities	575.2	505.3	382.5
Total pipeline operations revenues	874.9	658.6	486.2
Costs and Expenses			
Pipeline margin activities purchases	(554.6)	(487.1)	(362.2)
Field operating costs (excluding LTIP charge)	(121.1)	(60.9)	(40.1)
LTIP charge operations	(0.1)	(1.4)	
Segment G&A expenses (excluding LTIP charge)[2]	(38.1)	(18.3)	(13.2)
LTIP charge general and administrative	(3.8)	(9.6)	
Segment profit	$ 157.2	$ 81.3	$ 70.7
Maintenance capital	$ 8.3	$ 6.4	$ 3.4
Average Daily Volumes (thousands of barrels per day)[3]			
Tariff activities			
All American	54	59	65
Basin	265	263	93
Link acquisition	283	N/A	N/A
Capline	123	N/A	N/A
Other domestic	424	299	219
Canada	263	203	187
Total tariff activities	1,412	824	564
Pipeline margin activities	74	78	73
Total	1,486	902	637

(1)

Revenues and purchases include intersegment amounts.

(2) Segment G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on the business activities that existed at that time. The proportional allocations by segment require judgment by management and will continue to be based on the business activities that exist during each period.

(3) Volumes associated with acquisitions represent total volumes transported for the number of days we actually owned the assets divided by the number of days in the period.

Revenues from both our tariff activities and our pipeline margin activities have increased over the three year period ended December 31, 2004. The increase in revenues from tariff activities in both the 2004 and 2003 periods is primarily related to increased volumes resulting from our acquisition activities as discussed further below. The increase in revenue from our pipeline margin activities was related to higher average prices for crude oil sold and transported on our SJV gathering system in each of the years compared to the year prior. The increase in 2004 was partially offset by lower buy/sell volumes (as compared to 2003), while the 2003 period benefitted from higher buy/sell volumes (as compared to 2002). Because the barrels that we buy and sell are generally indexed to the same pricing indices, revenues and purchases will increase and decrease with changes in market prices without significant changes to our margins related to those purchases and sales.

Our buy/sell arrangements in our pipeline segment consisted of the following:

	Year Ended December 31,		
	2004	2003	2002
		(in millions)	
Barrels per day	12,000	17,000	10,000
Revenues (in millions)	$ 149.8	$ 166.2	$ 95.8
Purchases (in millions)	(142.5)	(159.2)	(87.6)
Margin (in millions)	$ 7.3	$ 7.0	$ 8.2

Increases in segment profit, our primary measure of segment performance, were driven by the following:

Increased volumes and related tariff revenues The increase in volumes and related tariff revenues in 2004 versus 2003 is primarily related to the Link acquisition, the Capline acquisition and other acquisitions completed during 2004 and late 2003. Similar increases in 2003 compared to 2002 are related to the acquisitions made in 2003, as well as the inclusion of the assets acquired in 2002 for a full year as compared to only a portion of 2002.

Higher realized prices on our loss allowance oil Higher crude oil prices during 2004 as compared to 2003 (the NYMEX average for 2004 was $41.29 per barrel versus $31.08 per barrel in 2003) have resulted in increased revenues related to loss allowance oil.

Increased field operating costs Our continued growth, primarily from the Link acquisition and other acquisitions completed during 2004 and late 2003 is the principal driver of the increase in field operating costs for 2004. The increased costs are primarily in payroll and benefits and utilities. The 2004 results also include a $1.7 million charge for a pipeline release of oil. In addition, costs related to pipeline and storage regulation have increased by approximately $2 million in 2004. The increase in field operating costs in 2003 as compared to 2002 was predominantly related to growth from acquisitions and higher utility costs. The 2003 period also includes a $1.4 million LTIP charge and a $1.0 million charge for a release of oil from a pipeline.

Increased segment G&A expenses The increase in segment G&A expenses in 2004 is primarily related to the Link acquisition coupled with the increase in the percentage of indirect costs allocated to the pipeline operations segment in the 2004 period as our pipeline operations have grown. G&A costs have also increased because of increased headcount from our continued

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growth and higher costs related to compliance activities attributable to Sarbanes-Oxley section 404 compliance. Costs related to section 404 compliance were $2.6 million in 2004. These items were partially offset by the inclusion of an LTIP charge of approximately $9.6 million in the 2003 period compared to $3.8 million in the 2004 period. The increase in 2003 as compared to 2002 is primarily related to the LTIP charge mentioned above, an overall increase in costs from our continued growth from acquisitions and increased indirect costs allocated to the pipeline operations segment as operations grew.

As discussed above, the increase in pipeline operations segment profit is largely related to our acquisition activities. We have completed a number of acquisitions during 2004 and 2003 that have impacted our results of operations. The following presentation summarizes the revenue and volume impact of recent acquisitions.

	Year Ended December 31,					
	2004		2003		2002	
	Revenues	Volumes	Revenues	Volumes	Revenues	Volumes
	(volumes in thousands of barrels per day and revenues in millions)					
Tariff activities[1][2]						
2004 acquisitions	$ 115.6	525	$ N/A	N/A	$ N/A	N/A
2003 acquisitions	39.7	170	14.8	82	N/A	N/A
2002 acquisitions	54.6	327	54.2	344	23.1	171
All other pipeline systems	89.8	390	84.3	398	80.6	393
Total tariff activities	$ 299.7	1,412	$ 153.3	824	$ 103.7	564

(1) Revenues include intersegment amounts.

(2) Volumes associated with acquisitions represent total volumes transported for the number of days we actually owned the assets divided by the number of days in the period.

The increase in 2004 is predominately related to (i) the inclusion of an average of 283,000 barrels per day and $79.3 million of revenues from the pipelines acquired in the Link acquisition, (ii) the inclusion of an average of approximately 123,000 barrels per day and $25.9 million of revenues from the Capline pipeline system and (iii) 119,000 barrels per day and $10.4 million of revenues from other 2004 acquisitions. Additionally, volumes and revenues have increased as a result of the inclusion for the full year of 2004 of several pipeline systems acquired during 2003 as compared to only a portion of the year in 2003 (See "Acquisitions"), coupled with higher realized prices on our loss allowance oil. Revenues from all other pipeline systems increased in the 2004 period, primarily related to slightly higher volumes on various systems. The appreciation of Canadian currency also favorably impacted revenues. The Canadian dollar to U.S. dollar exchange rate appreciated to an average of 1.30 to 1 for the year ended December 31, 2004, compared to an average of 1.40 to 1 for the year ended December 31, 2003.

The increase in 2003 relates to various acquisitions completed in 2003 along with the inclusion of assets acquired in 2002 for an entire year compared to only a portion of 2002.

Maintenance Capital

For the periods ended December 31, 2004, 2003 and 2002, maintenance capital expenditures were approximately $8.3 million, $6.4 million and $3.4 million, respectively for our pipeline operations segment. The increase in 2004 is because of the growth of our business, primarily related to the Link acquisition. The increase in 2003 is related to our continued growth, primarily through acquisitions.

Gathering, Marketing, Terminalling and Storage Operations

As of December 31, 2004, we owned approximately 37 million barrels of active above-ground crude oil terminalling and storage facilities, including a crude oil terminalling and storage facility at Cushing, Oklahoma. Cushing, which we refer to as the Cushing Interchange, is one of the largest crude oil market hubs in the United States and the designated delivery point for New York Mercantile Exchange, or NYMEX, crude oil futures contracts. Terminals are facilities where crude oil is transferred to or from storage or a transportation system, such as a pipeline, to another transportation system, such as trucks or another pipeline. The operation of these facilities is called "terminalling." Approximately 13.6 million barrels of our 37 million barrels of tankage is used primarily in our GMT&S Operations segment and the balance is used in our Pipeline Operations segment. On a stand-alone basis, segment profit from terminalling and storage activities is dependent on the throughput of volumes, the volume of crude oil stored and the level of fees generated from our terminalling and storage services. Our terminalling and storage activities are integrated with our gathering and marketing activities and the level of tankage that we allocate for our arbitrage activities (and therefore not available for lease to third parties) varies throughout crude oil price cycles. This integration enables us to use our storage tanks in an effort to counter-cyclically balance and hedge our gathering and marketing activities. In a contango market (when oil prices for future deliveries are higher than for current deliveries), we use our tankage to improve our gathering margins by storing crude oil we have purchased at lower prices in the current month for delivery at higher prices in future months. In a backwardated market (when oil prices for future deliveries are lower than for current deliveries), we use less storage capacity, but increased marketing margins (premiums for prompt delivery) provide an offset to this reduced cash flow. We believe that this combination of our terminalling and storage activities and gathering and marketing activities provides a counter-cyclical balance that has a stabilizing effect on our results of operations and cash flows.

Our revenues from gathering and marketing activities reflect the sale of gathered and bulk-purchased crude oil and LPG volumes, plus the sale of additional barrels exchanged through buy/sell arrangements entered into to supplement the margins of the gathered and bulk-purchased volumes. Because the commodities that we buy and sell are generally indexed to the same pricing indices for both the purchase and the sale, revenues and costs related to purchases will increase and decrease with changes in market prices. However, the margins related to those purchases and sales will not necessarily have corresponding increases and decreases. For example, our revenues increased approximately 69% in 2004 compared to 2003, while our segment profit increased approximately 45% in the same period.

Revenues from our GMT&S operations were approximately $20.2 billion, $12.0 billion and $7.9 billion for the years ended December 31, 2004, 2003 and 2002, respectively. Revenues and costs related to purchases for the 2004 period were impacted by higher average prices and higher volumes as compared to the 2003 period. Approximately 60% of the increase in revenues resulted from higher average prices in the 2004 period and the remainder was attributable to increased sales volumes. The average NYMEX price for crude oil was $41.29 per barrel and $31.08 per barrel for the years ended December 31, 2004 and 2003, respectively. The increase in revenues and costs related to purchases in 2003 was related to higher average prices and higher volumes in 2003 as compared to 2002. The average NYMEX price for crude oil was $26.10 per barrel in 2002.

Our buy/sell arrangements in our GMT&S segment consisted of the following:

	Year Ended December 31,		
	2004	2003	2002
Barrels per day[1]	790,000	545,000	460,000
Revenues (in millions)[1]	$ 11,247.0	$ 6,124.9	$ 4,140.8
Purchases (in millions)[1]	(11,137.7)	(5,967.2)	(4,026.2)
Margin (in millions)	$ 109.3	$ 157.7	$ 114.6

(1) Include certain estimates based on management's judgment; such estimates are not expected to have a material impact on the balances.

Generally, we expect our segment profit to increase or decrease directionally with increases or decreases in lease gathered volumes and LPG sales volumes. Although we believe that the combination of our lease gathering business and our storage assets provides a counter-cyclical balance that provides stability in our margins, these margins are not fixed and may vary from period to period. In order to evaluate the performance of this segment, management focuses on the following metrics: (i) segment profit, (ii) crude oil lease gathered volumes and LPG sales volumes and (iii) segment profit per barrel calculated on these volumes. The following table sets forth our operating results from our Gathering, Marketing, Terminalling and Storage Operations segment for the periods indicated:

	December 31,		
	2004	2003	2002
	(in millions, except per barrel amounts)		
Operating Results[1]			
Revenues	$ 20,223.5	$ 11,985.6	$ 7,921.8
Purchases and related costs	(19,992.8)	(11,799.8)	(7,765.1)
Field operating costs (excluding LTIP charge)	(97.5)	(73.3)	(66.3)
LTIP charge operations	(0.8)	(4.3)	
Segment G&A expenses (excluding LTIP charge)[2]	(37.7)	(31.6)	(31.5)
LTIP charge general and administrative	(3.2)	(13.5)	
Segment profit	$ 91.5	$ 63.1	$ 58.9
Noncash SFAS 133 impact[3]	$ 1.0	$ 0.4	$ 0.3
Maintenance capital	$ 3.0	$ 1.2	$ 2.6
Segment profit per barrel[4]	$ 0.39	$ 0.36	$ 0.36
Average Daily Volumes (thousands of barrels per day)[5]			
Crude oil lease gathered	589	437	410
Crude oil bulk purchases	148	90	68

	December 31,		
Total	737	527	478
LPG sales	48	38	35

(1) Revenue and purchases include intersegment amounts.

(2) Segment G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on the business activities that existed at that time. The proportional allocations by segment require judgment by management and will continue to be based on the business activities that exist during each period.

(3) Amounts related to SFAS 133 are included in revenues and impact segment profit.

(4) Calculated based on crude oil lease gathered barrels and LPG sales barrels.

(5) Volumes associated with acquisitions represent total volumes transported for the number of days we actually owned the assets divided by the number of days in the period.

Increases in segment profit, our primary measure of segment performance, were driven by the following:

Increased crude oil lease gathered volumes and LPG sales volumes The crude oil volumes gathered from producers, using our assets or third-party assets, have increased by approximately 35% in 2004. The increase is primarily related to the Link acquisition, which has offset natural production declines. In addition, we marketed 48,000 barrels per day of LPG during 2004 compared to 38,000 barrels per day in 2003.

Favorable market conditions During 2004, market conditions were favorable as the crude oil market experienced significant volatility and the market shifted between backwardation and contango multiple times during the year. Additionally, price differentials between grades of crude oil were wider than normal, enhancing results. The NYMEX benchmark price of crude ranged from $32.20 to $55.65 during the period. This volatile market allowed us to optimize and enhance the margins of both our gathering and marketing assets and our terminalling and storage assets at different times during the period. The market conditions in 2003 were also favorable as there was relatively high volatility and strong backwardation throughout the period. During 2003, the NYMEX benchmark price of crude ranged from $25.04 to $39.99 per barrel. Additionally, in the first quarter of 2003, cold weather throughout the U.S. and Canada led to increased LPG sales and higher margins.

Change in impact from the SFAS 133 mark-to-market adjustment The 2004 period included a non-cash gain of approximately $1.0 million resulting from the mark-to-market of open derivative instruments pursuant to SFAS 133, while the 2003 and 2002 periods included non-cash gains of approximately $0.4 million and $0.3 million, respectively.

Impact of change in Canadian dollar to U.S. dollar exchange rate The 2004 period includes a foreign exchange gain of $5.0 million. The gain is related to the impact of changes in the Canadian dollar to U.S. dollar exchange rate on a net U.S. dollar denominated liability of our Canadian subsidiary whose functional currency is the Canadian dollar. This is primarily attributable to our LPG business, a substantial amount of which is transacted in U.S. Dollars.

Lower-of-cost-or-market inventory adjustment The 2004 period included a charge of approximately $2.0 million related to a valuation adjustment on our LPG inventory. This charge is linked to the foreign exchange gain mentioned above, and is effectively a partial reversal of that gain.

Increased tankage available to our gathering and marketing business As a result of various acquisitions and expansion at our Cushing Terminal, the average amount of tankage available increased to 12.7 million barrels in 2004 from 11.0 million barrels in 2003 and 10 million barrels in 2002.

Increased field operating costs Our continued growth, primarily from the Link acquisition is the primary driver of the increase in field operating costs for 2004 as compared to 2003. This increase was partially offset by the $4.3 million charge related to our 1998 LTIP in the 2003 period compared to $0.8 million in 2004. Field operating costs increased in 2003 as compared to 2002 primarily because of the 1998 LTIP charge mentioned above. The remaining increase was partially related to our growth in 2003, primarily related to acquisitions, coupled with increased regulatory compliance activities and higher fuel costs.

Increased segment G&A expenses G&A increased in 2004, primarily related to an increase in employees resulting from continued growth and higher costs related to compliance activities attributable to Sarbanes-Oxley section 404 compliance partially offset by a decrease in the percentage of indirect costs allocated to the GMT&S operations segment as the growth in our pipeline operations segment has outpaced growth in our GMT&S operations segment. Costs related to section 404 compliance were $1.9 million in 2004. The increase is partially offset by the $13.5 million charge related to our LTIP in 2003 compared to $3.2 million in 2004. The increase in G&A in 2003 as compared to 2002 is primarily related to the 1998 LTIP charge mentioned above, partially offset by the decrease in indirect costs allocated to the GMT&S segment from period to period as our Pipeline Operations segment has grown.

The impact of the items discussed above resulted in segment profit per barrel (calculated based on our lease gathered crude oil and LPG barrels) of $0.39 per barrel for 2004, compared to $0.36 for both 2003 and 2002.

Maintenance Capital

For the periods ended December 31, 2004, 2003 and 2002, maintenance capital expenditures were approximately $3.0 million, $1.2 million and $2.6 million, respectively for our gathering, marketing, terminalling and storage operations segment. The increase in 2004 as compared to 2003 is primarily related to the Link acquisition. The decrease in 2003 as compared to 2002 was primarily because of a reduction in costs associated with information systems and the replacement of a portion of our fleet in 2002.

Other Income and Expenses

Unallocated G&A Expenses

Segment G&A expenses include the costs directly associated with the segments, as well as a portion of corporate overhead costs considered allocable. Total G&A expenses were $82.8 million, $73.0 million and $45.7 million for the years ended December 31, 2004, 2003 and 2002, respectively. We have included in the above segment discussion the G&A expenses for each of these years that were attributable to our segments either directly or by allocation. During 2002, we were unsuccessful in our pursuit of several sizable acquisition opportunities determined by auction and one negotiated transaction that had advanced nearly to the execution stage when it was abruptly terminated by the seller. As a result, our 2002 results reflect a $1.0 million charge to G&A expenses associated with the third-party costs of these unsuccessful transactions. This charge was not allocated to the segments.

Depreciation and Amortization

Depreciation and amortization expense was $67.2 million for the year ended December 31, 2004, compared to $46.8 million and $34.1 million for the years ended December 31, 2003 and 2002, respectively. The increase in 2004 relates primarily to the assets from our 2004 acquisitions and our various 2003 acquisitions being included for the full year versus only a part of the year in 2003. In addition, 2004 includes approximately $4.2 million of depreciation of trucks and trailers under capital leases. Amortization of debt issue costs was $2.5 million in 2004, compared to $3.8 million in 2003.

The increase in 2003 over 2002 relates primarily to the inclusion of the assets from the Shell acquisition for the entire year as compared to a portion of 2002. Additionally, several acquisitions were completed during the year along with various capital projects. Amortization of debt issue costs was flat between the two years.

Interest Expense

Interest expense was $46.7 million for the year ended December 31, 2004, compared to $35.2 million and $29.1 million for the years ended December 31, 2003 and 2002, respectively. In 2004, our average debt balance was $859.5 million. This balance consisted of fixed rate senior notes averaging $585.8 million and borrowings under our revolving credit facilities averaging $273.7 million. During the 2003 period, our average debt balance was approximately $525.5 million and consisted of fixed rate senior notes averaging $214.4 million and borrowings under our revolving credit facilities averaging $311.1 million. The higher average debt balance in 2004 was primarily related to the portion of our acquisitions that were not refinanced with equity. Our financial growth strategy is to fund our acquisitions using a balance of debt and equity.

During the third quarter of 2004, we issued $175 million of five year senior unsecured notes and $175 million of 12 year senior unsecured notes. These issuances resulted in an increase in the average amount of longer term and higher cost fixed rate debt outstanding in 2004 to approximately 68% as compared to approximately 41% in 2003. During 2004 and 2003, the average three-month LIBOR rate was 1.6% and 1.2%, respectively.

The higher average debt balance in 2004 resulted in additional interest expense of approximately $16.8 million, while at the same time our commitment and other fees decreased by approximately $0.4 million. Our weighted average interest rate, excluding commitment and other fees, was approximately 5.0% for 2004 compared to 6.0% for 2003. The lower weighted average rate decreased interest expense by approximately $4.9 million in 2004 compared to 2003.

The increase in 2003 compared to 2002 was primarily related to an increase in the average debt balance during the 2003 period to approximately $525.5 million from approximately $444.6 million in the 2002 period, which resulted in additional interest expense of approximately $5.0 million. The higher average debt balance was primarily due to the portion of the Shell acquisition that was not financed with equity. This debt was outstanding for all of 2003 versus only a portion of 2002. Also, increased commitment and other fees coupled with lower capitalized interest resulted in approximately $2.2 million of the increase in the 2003 period. Our weighted average interest rate decreased slightly during 2003 to 6.0% versus 6.2% in 2002, which decreased our interest expense by approximately $1.1 million. Although the change in our weighted average interest rate was nominal, the change was the net result of various factors that included an increase in the amount of fixed rate debt with longer maturities, long-term interest rate hedges and declining short-term interest rates. In mid-September 2002, we issued $200 million of ten-year bonds bearing a fixed interest rate of 7.75%. In the fourth quarter of 2002 and the first quarter of 2003, we entered into hedging arrangements to lock in interest rates on approximately $50 million of its floating rate debt. In addition, the average three-month LIBOR rate declined from approximately 1.8% during 2002 to approximately 1.2% during 2003. The net impact of these factors, increased commitment fees and changes in average debt balances decreased the average interest rate by 0.2%.

Other

During the third quarter of 2004, we completed (i) the issuance of 4,968,000 common units and (ii) the issuance of an aggregate of $350 million of senior unsecured notes. We used the proceeds from these issuances to, among other things, repay amounts outstanding under our revolving credit facilities, including all amounts outstanding under the $200 million, 364-day facility we used to fund the Link acquisition. The repayment and termination of this facility resulted in a non-cash charge of approximately $0.7 million associated with the write-off of unamortized debt issue costs. Additionally, during the fourth quarter of 2004, we recognized an impairment charge of approximately $2.0 million associated with taking our pipeline system in the Illinois Basin out of service. The impairment represents the remaining net book value of the idled pipeline system. This pipeline did not support spending the capital necessary to continue service and we shifted the majority of the gathering and transport activities to trucks. As a result, we were able to maintain most of our margins.

During the fourth quarter of 2003 we completed the refinancing of our bank credit facilities with new senior unsecured credit facilities totaling $750 million and a $200 million uncommitted facility for the purchase of hedged crude oil (See " Liquidity and Capital Resources Credit Facilities and Long-term Debt"). In addition, during the third quarter of 2003 we made a $34 million prepayment on our Senior secured term B loan in anticipation of the refinancing. The completion of these transactions resulted in a non-cash charge of approximately $3.3 million associated with the write-off of unamortized debt issue costs.

Outlook

This section identifies certain matters of risk and uncertainty that may affect our financial performance and results of operations in the future.

Ongoing Acquisition Activities. Consistent with our business strategy, we are continuously engaged in discussions with potential sellers regarding the possible purchase by us of transportation, gathering, terminalling or storage assets and related businesses. These acquisition efforts often involve assets which, if acquired, would have a material effect on our financial condition and results of operations. In an effort to prudently and economically leverage our asset base, knowledge base and skill sets, management has also expanded its efforts to encompass businesses that are closely related to, or significantly intertwined with, the crude oil business. We can give no assurance that our current or future acquisition efforts will be successful or that any such acquisition will be completed on terms considered favorable to us.

OCS Production. In October 2004, Plains Exploration and Production ("PXP") announced that it had successfully completed an initial development well into the Rocky Point field, which is accessible from the Point Arguello platforms and that drilling operations are underway on a second development well. We can give no assurances, however, that our volumes transported would increase as a result of this drilling activity.

Pipeline Integrity and Storage Tank Testing Compliance. Although we believe our short-term estimates of costs under the pipeline integrity management rules and API 653 (and similar Canadian regulations) are reasonable, a high degree of uncertainty exists with respect to estimating such costs, as we continue to test existing assets and as we acquire new assets.

Sarbanes Oxley Act and Related Legislation. Several regulatory and legislative initiatives were introduced in 2002 and 2003 in response to developments during 2001 and 2002 regarding accounting issues at large public companies, resulting disruptions in the capital markets and ensuing calls for action to prevent recurrence of similar events. We believe implementation of reforms in connection with these initiatives have added to the costs of doing business for most publicly traded entities, including us as a partnership. These costs will have an adverse impact on future income and cash flow.

Longer Term Outlook. Our longer-term outlook, spanning a period of five or more years, is influenced by many factors affecting the North American crude oil sector. Some of the more significant trends and factors include:

1. Continued overall depletion of U.S. crude oil production.

2. The continuing convergence of worldwide crude oil supply and demand trends.

3. Aggressive practices in the U.S. to maintain working crude oil inventory levels below historical levels despite rising demand in North America.

4. Industry compliance with the Department of Transportation's adoption of the American Petroleum Institute's standard 653 for testing and maintenance of storage tanks, which will require significant investments to maintain existing crude oil storage capacity or, alternatively, will result in a reduction of existing storage capacity by 2009.

5. The expectation of increased crude oil production from certain North American regions (primarily Canadian oil sands and deepwater Gulf of Mexico sources) that will, of economic necessity, compete for U.S. markets currently being supplied by non-North American foreign crude imports.

We believe the collective impact of these trends, factors and developments, many of which are beyond our control, will result in an increasingly volatile crude oil market that is subject to more frequent short-term swings in market prices and grade differentials and shifts in market structure. In an environment of reduced inventories and tight supply and demand balances, even relatively minor supply disruptions can cause significant price swings. Conversely, despite a relatively balanced market on a global basis, competition within a given region of the U.S. could cause downward pricing pressure and significantly impact regional crude oil price differentials among crude oil grades and locations. Although we believe our business strategy is designed to manage these trends, factors and potential developments, and that we are strategically positioned to benefit from certain of these developments, there can be no assurance that we will not be negatively affected.

Liquidity and Capital Resources

Liquidity

Cash generated from operations and our credit facilities are our primary sources of liquidity. At December 31, 2004, we had a working capital deficit of approximately $12.5 million, approximately $420.2 million of availability under our committed revolving credit facilities and $344.6 million of unused capacity under our uncommitted hedged inventory facility. Usage of the credit facilities is subject to compliance with covenants. We believe we are currently in compliance with all covenants. In January 2005, we had additional net borrowings under our uncommitted hedged inventory facility of approximately $236.8 million. The proceeds were used to pay for crude oil stored at December 31, 2004.

Capital Resources

We periodically access the capital markets for both equity and debt financing. In April 2004, we completed the private placement of 3,245,700 units of Class C common units to a group of institutional investors comprised of affiliates of Kayne Anderson Capital Advisors, Vulcan Capital and Tortoise Capital Advisors for $30.81 per unit. Total proceeds from the transaction, after deducting transaction costs and including the general partner's proportionate contribution, was approximately $101 million. In the third quarter of 2004, we completed a public offering of 4,968,000 common units for $33.25 per unit. The offering resulted in gross proceeds of approximately $165.2 million from the sale of units and approximately $3.4 million from our general partner's proportionate capital contribution. Total costs associated with the offering, including underwriter fees and other expenses, were approximately $7.7 million. Net proceeds of $160.9 million were used to permanently reduce outstanding borrowings under the $200 million, 364-day credit facility.

In August 2004, we completed the sale of $350 million of senior notes. We used the net proceeds, after deducting initial purchaser discounts and offering costs, of approximately $345 million to repay amounts outstanding under our credit facilities, including the remaining balance under the $200 million, 364-day facility we used to fund the Link acquisition, and for general partnership purposes. In connection with this repayment, we terminated the facility. Subsequent to the notes offering, we also terminated our $125 million, 364-day facility, which was scheduled to expire in November 2004.

Capital Expenditures

We have made and will continue to make capital expenditures for acquisitions, expansion capital and maintenance capital. Historically, we have financed these expenditures primarily with cash generated by operations, credit facility borrowings, the issuance of senior unsecured notes and the sale of additional common units.

We expect to invest approximately $100 million on expansion capital projects during 2005. Our 2005 expansion capital projects include the following notable projects with the estimated cost for the entire year.

	Estimated to be incurred in 2005 (in millions)
Capital projects and upgrades associated with the Link acquisition	$ 18.0
Trenton pipeline expansion	16.0
Cushing Phase V expansion	13.0
Cal Ven fractionator	16.0
Capital projects and upgrades associated with the Shell South Louisiana Assets acquisition	8.0
Other	29.0
	$ 100.0

In addition, we expect to invest approximately $19.0 million on maintenance capital projects during 2005.

We believe that we have sufficient liquid assets, cash flow from operations and borrowing capacity under our credit agreements to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures. However, we are subject to business and operational risks that could adversely affect our cash flow. A material decrease in our cash flows would likely produce an adverse effect on our borrowing capacity.

Cash Flows

Cash flows for the years ended December 31, 2004, 2003 and 2002 were as follows:

	Year Ended December 31,		
	2004	2003	2002
	(in millions)		
Cash provided by (used in):			
Operating activities	$ 104.0	$ 115.3	$ 185.0
Investing activities	(651.2)	(272.1)	(374.9)
Financing activities	554.5	157.2	189.5

Operating Activities. The primary drivers of our cash flow from operations are (i) the collection of amounts related to the sale of crude oil and LPG and the transportation of crude oil for a fee and (ii) the payment of amounts related to the purchase of crude oil and LPG and other expenses, principally field operating costs and general and administrative expenses. The cash settlement from the purchase and sale of crude oil during any particular month typically occurs within thirty days from the end of the month, except in the months that we store inventory because of contango market conditions or in months that we increase linefill. The storage of crude oil in periods of a contango market can have a material impact on our cash flows from operating activities for the period we pay for and store the crude oil and the subsequent period that we receive proceeds from the sale of the crude oil. When we store the crude oil, we borrow on our credit facilities to pay for the crude oil so the impact on operating cash flow is negative. Conversely, cash flow from operations increases in the period we collect the cash from the sale of the stored crude oil. In addition, our cash flow from operating activities is also impacted by the level of LPG inventory stored at period end.

Cash flow from operations was $104.0 million in 2004 and reflects cash generated by our recurring operations that was offset negatively by several factors totaling approximately $100 million. The primary item was a net increase in hedged crude oil and LPG inventory and linefill in third party assets that was financed with borrowings under our credit facilities (approximately $75 million net). Cash flows from operations were also negatively impacted by a decrease of approximately $20 million in prepayments received from counter parties to mitigate credit risk.

Our positive cash flow from operations for 2003 resulted from cash generated by our recurring operations. In addition, cash flow from operating activities was positively impacted by approximately $74 million related to proceeds received in 2003 from the sale of 2002 hedged crude oil inventory and negatively impacted by approximately $100 million related to inventory stored at the end of 2003. The proceeds from the sale of the 2003 stored crude oil were received in the first quarter of 2004. In 2003, we also received approximately $23 million of additional prepayments over the 2002 balance from counter parties to mitigate our credit risk, and paid approximately $6.2 million to terminate an interest rate hedge in conjunction with a change in our capital structure.

Our positive cash flow from operations for 2002 resulted from cash generated by our recurring operations. In addition, we received approximately $93 million of proceeds during 2002 associated with crude oil hedged and stored during 2001. This was partially offset by the payment of approximately $74 million for crude oil purchased and stored during 2002 but for which receipt of the proceeds occurred during 2003. In addition, our 2002 cash flow from operating activities was positively impacted by the collection of approximately $21 million of prepayments from counter parties to mitigate our credit risks and the collection of approximately $9.1 million of amounts that had been outstanding primarily since 1999 and 2000.

Investing Activities. Net cash used in investing activities in 2004, 2003 and 2002 consisted predominantly of cash paid for acquisitions. Net cash used in 2004 was approximately $651 million and was comprised primarily of cash paid for acquisitions of $535 million, which included (i) approximately $294 million for the Link acquisition, (ii) approximately $143 million for the Capline/Capwood acquisition (a deposit of $15.8 million was paid during 2003), (iii) approximately $47 million for the Schafferstown Propane Storage Facility (including approximately $14.2 million of working inventory) and (iv) approximately $51 million related to various other acquisitions. Investing activities for 2004 also included over $115 million of property and equipment construction and capitalized maintenance projects, which includes approximately $34 million related to the Cushing to Broome pipeline construction project.

Net cash used in investing activities 2003 was $272.1 million and was comprised of (i) an aggregate $152.6 million paid primarily for ten acquisitions completed during 2003, (ii) a $15.8 million deposit paid on the Capline acquisition; see " Acquisitions", (iii) proceeds of approximately $8.5 million from sales of assets, and (iv) $65.4 million paid for additions to property and equipment, including $19.2 million related to the construction of crude oil gathering and transmission lines in West Texas, and (v) crude oil linefill purchases of approximately $47 million, primarily attributable to increased linefill requirements related to 2003 and 2002 acquisitions. Net cash used in 2002 was $374.9 million and was comprised of (i) an aggregate $324.6 million paid for three acquisitions completed during 2002; see " Acquisitions", and (ii) $40.6 million paid for additions to property and equipment, primarily related to our Cushing expansion and the construction of the Marshall terminal in Canada, and (iii) crude oil linefill purchases of approximately $11 million.

Financing Activities. Cash provided by financing activities in 2004 consisted primarily of $348.1 million of net proceeds from the issuance of senior notes and $262.1 million of net proceeds from the issuance of common units, used primarily to fund acquisitions and pay down outstanding balances on our revolving credit facilities. Net borrowings under our short-term and long-term revolving credit facilities were $107.7 million. In addition, $158.4 million of distributions were paid to our unitholders and general partner.

Cash provided by financing activities in 2003 consisted primarily of $499.7 million of net proceeds from the issuance of common units and senior unsecured notes, used primarily to fund capital projects and acquisitions and pay down outstanding balances on our revolving credit facilities and senior term loans. Net repayments of our short-term and long-term revolving credit facilities and related senior term loans were $215.4 million. In addition, $121.8 million of distributions were paid to our unitholders and general partner. Cash provided by financing activities in 2002 consisted of approximately $344.6 million of net proceeds from the issuance of common units and senior unsecured notes, used primarily to fund capital projects and acquisitions and pay down outstanding balances on the revolving credit facility. Net repayments of our short-term and long-term revolving credit facilities during 2002 were $49.9 million. In addition, $99.8 million of distributions were paid to our unitholders and general partner during the year ended December 31, 2002.

Credit Facilities and Long-term Debt

During August 2004, we completed the sale of $175 million of 4.75% senior notes due 2009 and $175 million of 5.88% senior notes due 2016. The 4.75% notes were sold at 99.551% of face value and the 5.88% notes were sold at 99.345% of face value. We used the net proceeds, after deducting initial purchaser discounts and offering costs, of approximately $345 million to repay amounts outstanding under our credit facilities, including the remaining balance under the $200 million, 364-day facility funded in connection with the Link acquisition, and for general partnership purposes. In connection with this repayment, we terminated the facility. Subsequent to the notes offering, we also terminated our $125 million, 364-day facility that was scheduled to expire in November 2004.

In November 2004, we entered into a new $750 million, five-year senior unsecured credit facility, which contains a sub-facility for Canadian borrowings of up to $300 million. The new credit facility extends our maturities, lowers our cost of credit and provides an additional $125 million of liquidity over our previous facilities. This facility can be expanded to $1 billion. As of December 31, 2004, we had approximately $231.8 million outstanding under this credit facility, as well as $98.0 million in letters of credit outstanding, resulting in unused capacity under the facility of approximately $420.2 million.

Also in the fourth quarter of 2004, we amended and renewed our secured hedged inventory facility; increasing the facility to $425 million, with the ability to further increase the facility in the future by an incremental $75 million. This facility is an uncommitted working capital facility, which is used to finance the purchase of hedged crude oil inventory for storage when market conditions warrant. Borrowings under the hedged inventory facility are secured by the inventory purchased under the facility and the associated accounts receivable, and will be repaid with the proceeds from the sale of such inventory. This facility expires in November 2005. As of December 31, 2004, we had approximately $80.4 million outstanding and no letters of credit issued under our hedged crude oil inventory facility resulting in unused uncommitted capacity under this facility of approximately $344.6 million.

Our credit agreements and the indentures governing our senior notes contain cross default provisions. Our credit agreements prohibit distributions on, or purchases or redemptions of, units if any default or event of default is continuing. In addition, the agreements contain various covenants limiting our ability to, among other things:

- incur indebtedness if certain financial ratios are not maintained;
- grant liens;
- engage in transactions with affiliates;

- enter into sale-leaseback transactions;

- sell substantially all of our assets or enter into a merger or consolidation.

Our credit facility treats a change of control as an event of default and also requires us to maintain:

- an interest coverage ratio that is not less than 2.75 to 1.0; and

- a debt coverage ratio which will not be greater than 4.75 to 1.0 on all outstanding debt and 5.25 to 1.0 on all outstanding debt during an acquisition period (generally, the period consisting of three fiscal quarters following an acquisition greater than $50 million).

For covenant compliance purposes, letters of credit and borrowings to fund hedged inventory and margin requirements are excluded when calculating the debt coverage ratio.

A default under our credit facility would permit the lenders to accelerate the maturity of the outstanding debt. As long as we are in compliance with our credit agreements, our ability to make distributions of available cash is not restricted. We are currently in compliance with the covenants contained in our credit agreements and indentures.

Contingencies

Export License Matter. In our gathering and marketing activities, we import and export crude oil from and to Canada. Exports of crude oil are subject to the "short supply" controls of the Export Administration Regulations ("EAR") and must be licensed by the Bureau of Industry and Security (the "BIS") of the U.S. Commerce Department. In 2002, we determined that we may have violated the terms of our licenses with respect to the quantity of crude oil exported and the end-users in Canada. Export of crude oil except as authorized by license is a violation of the EAR. In October 2002, we submitted to the BIS an initial notification of voluntary disclosure. The BIS subsequently informed us that we could continue to export while previous exports were under review. We applied for and received several new licenses allowing for export volumes and end users that more accurately reflect our anticipated business and customer needs. We also conducted reviews of new and existing contracts and implemented new procedures and practices in order to monitor compliance with applicable laws regarding the export of crude oil to Canada. As a result, we subsequently submitted additional information to the BIS in October 2003 and May 2004. In August 2004, we received a request from the BIS for additional information. We have responded to this and subsequent requests, and continue to cooperate fully with BIS officials. At this time, we have received neither a warning letter nor a charging letter, which could involve the imposition of penalties, and no indication of what penalties the BIS might assess. As a result, we cannot reasonably estimate the ultimate impact of this matter.

Alfons Sperber v. Plains Resources Inc., et al. On December 18, 2003, a putative class action lawsuit was filed in the Delaware Chancery Court, New Castle County, entitled Alfons Sperber v. Plains Resources Inc., et al. This suit, brought on behalf of a putative class of Plains All American Pipeline, L.P. common unitholders, asserted breach of fiduciary duty and breach of contract claims against us, Plains AAP, L.P., and Plains All American GP LLC and its directors, as well as breach of fiduciary duty claims against Plains Resources Inc. and its directors. The complaint sought to enjoin or rescind a proposed acquisition of all of the outstanding stock of Plains Resources Inc., as well as declaratory relief, an accounting, disgorgement and the imposition of a constructive trust, and an award of damages, fees, expenses and costs, among other things. This lawsuit has been settled in principle. The court has approved the settlement and the settlement became final in March 2005.

Pipeline Releases. In December 2004 and January 2005, we experienced two unrelated releases of crude oil that reached rivers located near the sites where the releases originated. In late December 2004, one of our pipelines in West Texas experienced a rupture that resulted in the release of approximately 4,500 barrels of crude oil, a portion of which reached a remote location of the Pecos River. In early January 2005, an overflow from a temporary storage tank located in East Texas resulted in the release of approximately 1,200 barrels of crude oil, a portion of which reached the Sabine River. In both cases, emergency response personnel under the supervision of a unified command structure consisting of representatives of Plains Pipeline, the U.S. Environmental Protection Agency, the Texas Commission on Environmental Quality and the Texas Railroad Commission conducted clean-up operations at each site. Approximately 4,200 barrels and 980 barrels were recovered from the two respective sites. The unrecovered oil has been or will be removed or otherwise addressed by PAA in the course of site remediation. Aggregate costs associated with each release, including estimated remediation costs, are estimated at approximately $1.7 million and $1.4 million, respectively. We continue to work with the appropriate state and federal environmental authorities in responding to the releases and no enforcement proceedings have been instituted by any governmental authority at this time.

General. We, in the ordinary course of business, are a claimant and/or a defendant in various legal proceedings. We do not believe that the outcome of these legal proceedings, individually or in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows.

Environmental. We may experience future releases of crude oil into the environment from our pipeline, gathering and storage operations, or discover past releases that were previously unidentified. Although we maintain an inspection program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to any such environmental releases from our assets may substantially affect our business. At December 31, 2004, our reserve for environmental liabilities totaled approximately $19.8 million. Approximately $12.7 million of the reserve is related to liabilities assumed as part of the Link acquisition. Although we believe our reserve is adequate, no assurance can be given that any costs incurred in excess of this reserve would not have a material adverse effect on our financial condition, results of operations or cash flows.

Other. A pipeline, terminal or other facility may experience damage as a result of an accident or natural disaster. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance of various types that we consider adequate to cover our operations and properties. The insurance covers our assets in amounts considered reasonable. The insurance policies are subject to deductibles that we consider reasonable and not excessive. Our insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues. The overall trend in the environmental insurance industry appears to be a contraction in the breadth and depth of available coverage, while costs, deductibles and retention levels have increased. Absent a material favorable change in the insurance markets, this trend is expected to continue as we continue to grow and expand. As a result, we anticipate that we will elect to self-insure more of our activities or incorporate higher retention in our insurance arrangements.

The occurrence of a significant event not fully insured, indemnified or reserved against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe we are adequately insured for public liability and property damage to others with respect to our operations. With respect to all of our coverage, no assurance can be given that we will be able to maintain adequate insurance in the future at rates we consider reasonable, or that we have established adequate reserves to the extent that such risks are not insured.

Commitments

Contractual Obligations. In the ordinary course of doing business we purchase crude oil and LPG from third parties under contracts, the majority of which range in term from thirty-day evergreen to three years. We establish a margin for these purchases by entering into various types of physical and financial sale and exchange transactions through which we seek to maintain a position that is substantially balanced between crude oil and LPG purchases and sales and future delivery obligations. The table below includes purchase obligations related to these activities. Where applicable the amounts presented represent the net obligations associated with buy/sell contracts and those subject to a net settlement arrangement with the counterparty. We do not expect to use a significant amount of internal capital to meet these obligations, as the obligations will be funded by corresponding sales to credit worthy entities.

The following table includes our best estimate of the amount and timing of these payments as well as others due under the specified contractual obligations as of December 31, 2004.

	2005	2006	2007	2008	2009	Thereafter
	(in millions)					
Long-term debt and interest payments[1]	$ 49.7	$ 49.7	$ 49.7	$ 49.7	$ 368.0	$ 799.7
Leases[2]	17.8	14.0	10.9	6.3	5.2	13.7
Capital expenditure obligations	20.6					
Other long-term liabilities[3]	2.8	4.9	3.5	1.6	1.1	3.0
Subtotal	90.9	68.6	64.1	57.6	374.3	816.4
Crude oil and LPG purchases[4]	1,265.7	20.0	2.0	2.0	1.0	
Total	$ 1,356.6	$ 88.6	$ 66.1	$ 59.6	$ 375.3	$ 816.4

(1) Includes debt service payments, interest payments due on our senior notes and the commitment fee on our revolving credit facility. While there is an outstanding balance on our revolving credit facility at December 31, 2004 (this amount is included in the amounts above), we historically repay and borrow at varying amounts. As such, we have included only the maximum commitment fee (as if no amounts were outstanding on the facility) in the amounts above.

(2) Leases are primarily for office rent and trucks used in our gathering activities.

(3) Excludes approximately $10.6 million non-current liability related to SFAS 133 which are included in crude oil and LPG purchases.

(4) Amounts are based on estimated volumes and market prices. The actual physical volume purchased and actual settlement prices may vary from the assumptions used in the table. Uncertainties involved in these estimates include levels of production at the wellhead, weather conditions, changes in market prices and other conditions beyond our control.

Letters of Credit. In connection with our crude oil marketing, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the crude oil is purchased. Generally, these letters of credit are issued for up to seventy-day periods and are terminated upon completion of each transaction. At December 31, 2004, we had outstanding letters of credit of approximately $98.0 million.

Distributions. We plan to distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash is generally defined as all cash and cash equivalents on hand at the end of the quarter less reserves established by our general partner for future requirements. On February 14, 2005, we paid a cash distribution of $0.6125 per unit on all outstanding units. The total distribution paid was approximately $45.0 million, with approximately $41.2 million paid to our common unitholders and approximately $3.8 million paid to our general partner for its general partner ($0.8 million) and incentive distribution interests ($3.0 million).

Our general partner is entitled to incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, our general partner is entitled, without duplication, to 15% of amounts we distribute in excess of $0.450 per limited partner unit, 25% of amounts we distribute in excess of $0.495 per limited partner unit and 50% of amounts we distribute in excess of $0.675 per limited partner unit. In 2004, we paid $8.3 million in incentive distributions to our general partner. See "Certain Relationships and Related Transactions Our General Partner."

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements as defined by Item 303 of Regulation S-K.

Quantitative and Qualitative Disclosures About Market Risks

We are exposed to various market risks, including volatility in (i) crude oil and LPG commodity prices, (ii) interest rates and (iii) currency exchange rates. We utilize various derivative instruments to manage such exposure. Our risk management policies and procedures are designed to monitor interest rates, currency exchange rates, NYMEX and over-the-counter positions, and physical volumes, grades, locations and delivery schedules to ensure our hedging activities address our market risks. We have a risk management function that has direct responsibility and authority for our risk policies and our trading controls and procedures and certain aspects of corporate risk management. To hedge the risks discussed above we engage in risk management activities that we categorize by the risks we are hedging. The following discussion addresses each category of risk.

Commodity Price Risk

We hedge our exposure to price fluctuations with respect to crude oil and LPG in storage, and expected purchases and sales of these commodities. The derivative instruments utilized consist primarily of futures and option contracts traded on the NYMEX and over-the-counter transactions, including crude oil swap and option contracts entered into with financial institutions and other energy companies. Our policy is to purchase only crude oil for which we have a market, and to structure our sales contracts so that crude oil price fluctuations do not materially affect the segment profit we receive. Except for the controlled trading program discussed below, we do not acquire and hold crude oil futures contracts or other derivative products for the purpose of speculating on crude oil price changes that might expose us to indeterminable losses.

While we seek to maintain a position that is substantially balanced within our crude oil lease purchase and LPG activities, we may experience net unbalanced positions for short periods of time as a result of production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions. In connection with managing these positions and maintaining a constant presence in the marketplace, both necessary for our core business, we engage in a controlled trading program for up to an aggregate of 500,000 barrels of crude oil.

In order to hedge margins involving our physical assets and manage risks associated with our crude oil purchase and sale obligations, we use derivative instruments, including futures and options transactions, as well as over-the-counter instruments. In analyzing our risk management activities, we draw a distinction between enterprise level risks and trading related risks. Enterprise level risks are those that underlie our core businesses and may be managed based on whether there is value in doing so. Conversely, trading related risks (the risks involved in trading in the hopes of generating an increased return) are not inherent in the core business; rather, those risks arise as a result of engaging in the trading activity. We have a Risk Management Committee that approves all new risk management strategies through a formal process. With the exception of the controlled trading program, our approved strategies are intended to mitigate enterprise level risks that are inherent in our core businesses of gathering and marketing and storage.

Although the intent of our risk-management strategies is to hedge our margin, not all of our derivatives qualify for hedge accounting. In such instances, changes in the fair values of these derivatives will receive mark-to-market treatment in current earnings, and result in greater potential for earnings volatility. This accounting treatment is discussed further under Note 2 "Summary of Significant Accounting Policies" of our Consolidated Financial Statements.

All of our open commodity price risk derivatives at December 31, 2004 were categorized as non-trading. The fair value of these instruments and the change in fair value that would be expected from a 10 percent price decrease are shown in the table below (in millions):

	Fair Value	Effect of 10% Price Decrease
Crude oil:		
Futures contracts	$ 42.3	(11.8)
Swaps and options contracts	(5.1)	(5.1)
LPG:		
Swaps and option contracts	2.3	(2.7)

The fair values of the futures contracts are based on quoted market prices obtained from the NYMEX. The fair value of the swaps and option contracts are estimated based on quoted prices from various sources such as independent reporting services, industry publications and brokers. These quotes are compared to the contract price of the swap, which approximates the gain or loss that would have been realized if the contracts had been closed out at year end. For positions where independent quotations are not available, an estimate is provided, or the prevailing market price at which the positions could be liquidated is used. The assumptions in these estimates as well as the source is maintained by the independent risk control function. All hedge positions offset physical exposures to the cash market; none of these offsetting physical exposures are included in the above table. Price-risk sensitivities were calculated by assuming an across-the-board 10 percent decrease in price regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. In the event of an actual 10 percent change in prompt month crude prices, the fair value of our derivative portfolio would typically change less than that shown in the table due to lower volatility in out-month prices.

Interest Rate Risk

We utilize both fixed and variable rate debt, and are exposed to market risk due to the floating interest rates on our credit facilities. Therefore, from time to time we utilize interest rate swaps and collars to hedge interest obligations on specific debt issuances, including anticipated debt issuances. There are no interest rate hedging instruments outstanding as of December 31, 2004. The table below presents principal payments and the related weighted average interest rates by expected maturity dates for variable rate debt outstanding at December 31, 2004. All of our senior notes are fixed rate notes and their interest rates are not subject to market risk. Our variable rate debt bears interest at LIBOR, prime or the bankers acceptance rate plus the applicable margin. The average interest rates presented below are based upon rates in effect at December 31, 2004. The carrying values of the variable rate instruments in our credit facilities approximate fair value primarily because interest rates fluctuate with prevailing market rates, and the credit spread on outstanding borrowings reflects market.

	Expected Year of Maturity						
	2005	2006	2007	2008	2009	Thereafter	Total
	(in millions)						
Liabilities:							
Short-term debt variable rate	$ 168.6	$	$	$	$	$	168.6
Average interest rate	3.4%						3.4
Long-term debt variable rate	$	$	$	$	$ 143.6		143.6
Average interest rate					3.5%		3.5%

Currency Exchange Risk

Our cash flow stream relating to our Canadian operations is based on the U.S. dollar equivalent of such amounts measured in Canadian dollars. 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.

Because a significant portion of our Canadian business is conducted in Canadian dollars, we use certain financial instruments to minimize the risks of changes in the exchange rate. These instruments include forward exchange contracts and cross currency swaps. Neither the forward exchange contracts nor the cross currency swaps qualify for hedge accounting in accordance with SFAS 133.

At December 31, 2004, we had forward exchange contracts that allow us to exchange Canadian dollars for U.S. dollars, quarterly, at set exchange rates as detailed below:

	Canadian Dollars	US Dollars	Total
	($ in millions)		
2005	$ 3.0	$ 2.3	1.33 to 1
2006	$ 2.0	$ 1.5	1.32 to 1

In addition, at December 31, 2004, we also had cross currency swap contracts for an aggregate notional principal amount of $21.0 million effectively converting this amount of our U.S. dollar denominated debt to $32.5 million of Canadian dollar debt (based on Canadian dollar to U.S. dollar exchange rate of 1.55 to 1). The notional principal amount reduces by $2.0 million U.S. in May 2005 and has a final maturity in May 2006 ($19.0 million U.S.). At December 31, 2004, $9.9 million of our long-term debt was denominated in Canadian dollars ($11.9 million Canadian based on a Canadian dollar to U.S. dollar exchange rate of 1.20 to 1). All of these financial instruments are placed with what we believe to be large, creditworthy financial institutions.

We estimate the fair value of these instruments based on current termination values. The table shown below summarizes the fair value of our foreign currency hedges by year of maturity (in millions):

	Year of Maturity				
	2005	2006	2007	2008	Total
Forward exchange contracts	$ (0.9)	$ (0.6)	$	$	$ (1.5)
Cross currency swaps	(0.9)	(5.4)			(6.3)
Total	$ (1.8)	$ (6.0)	$	$	$ (7.8)

Three Months Ended March 31, 2005 and 2004

Operating Results Overview

During the first quarter of 2005, we recognized net income of $32.8 million and earnings per limited partner unit of $0.43, compared to $27.9 million and $0.44, respectively during the first quarter of 2004.

Key items in the first quarter of 2005 included:

- The contribution in the current quarter of acquisitions completed during 2004 and the first quarter of 2005.

- The inclusion in the first quarter of 2005 of an aggregate charge of approximately $2.2 million related to both our 1998 Long-Term Incentive Plan ("1998 LTIP") and our 2005 Long-Term Incentive Plan ("2005 LTIP").

- A non-cash loss of approximately $13.4 million in the first quarter of 2005 resulting from the mark-to-market of open derivative instruments pursuant to Statement of Financial Accounting Standard No. 133, as amended ("SFAS 133").

- Favorable market conditions characterized by relatively strong contango market conditions and reasonably high volatility and wide differentials in various grades of crude oil.

Acquisition Activities

We completed several acquisitions during 2005 and 2004 that have impacted the results of operations and liquidity discussed herein. The following acquisitions were accounted for, and the purchase prices were allocated, in accordance with SFAS 141 "Business Combinations." Our ongoing acquisition activity is discussed further in "Outlook" below.

During the first quarter of 2005, we completed several small transactions for aggregate consideration of approximately $24.3 million. The transactions included several crude oil pipeline systems along the Gulf Coast as well as in Canada. We also acquired an LPG pipeline and terminal in Oklahoma. These acquisitions did not materially impact our results of operations, either individually or in the aggregate.

During 2004, we completed several acquisitions for aggregate consideration of approximately $549.5 million. The aggregate consideration includes cash paid, estimated transaction costs and assumed liabilities and net working capital items. The following table summarizes our 2004 acquisitions:

Acquisition	Effective Date	Acquisition Price	Operating Segment
		(in millions)	
Capline and Capwood Pipeline Systems ("Capline acquisition")	03/01/04	$ 158.5	Pipeline
Link Energy LLC ("Link acquisition")	04/01/04	332.3	Pipeline/GMT&S
Cal Ven Pipeline System	05/01/04	19.0	Pipeline
Schaefferstown Propane Storage Facility	08/25/04	32.0	GMT&S
Other	various	7.7	GMT&S
Total 2004 Acquisitions		$ 549.5	

Results of Operations

Analysis of Operating Segments

Our operations consist of two operating segments: (i) Pipeline Operations and (ii) GMT&S Operations. Through our pipeline segment, we engage in interstate and intrastate crude oil pipeline transportation and certain related margin activities. Through our GMT&S segment, we engage in purchases and resales of crude oil and LPG at various points along the distribution chain and we operate certain terminalling and storage assets. We believe that the combination of our terminalling and storage activities and gathering and marketing activities provides a counter-cyclical balance that has a stabilizing effect on our results of operations and cash flow. In a contango market (oil prices for future deliveries are higher than for current deliveries), we use our tankage to improve our gathering margins by storing crude oil we have purchased at lower prices in the current month for delivery at higher prices in future months. In a backwardated market (oil prices for future deliveries are lower than for current deliveries), we use less storage capacity, but increased marketing margins (premiums for prompt delivery) provide an offset to this reduced cash flow.

We evaluate segment performance based on segment profit and maintenance capital. We define segment profit as revenues less (i) purchases, (ii) field operating costs and (iii) segment general and administrative ("G&A") expenses. Each of the items above excludes depreciation and amortization. As a master limited partnership, we make quarterly distributions of our "available cash" (as defined in our partnership agreement) to our unitholders. Therefore, we look at each period's earnings before non-cash depreciation and amortization as an important measure of segment performance. The exclusion of depreciation and amortization expense could be viewed as limiting the usefulness of segment profit as a performance measure because it does not account in current periods for the implied reduction in value of our capital assets, such as crude oil pipelines and facilities, caused by aging and wear and tear. Management compensates for this limitation by recognizing that depreciation and amortization are largely offset by repair and maintenance costs, which keep the actual value of our principal fixed assets from declining. These maintenance costs are a component of field operating costs included in segment profit or in maintenance capital, depending on the nature of the cost. Maintenance capital consists of capital expenditures required either to maintain the existing operating capacity of partially or fully depreciated assets or to extend their useful lives. Capital expenditures made to expand our existing capacity, whether through construction or acquisition, are not considered maintenance capital expenditures. Repair and maintenance expenditures associated with existing assets that do not extend the useful life or expand the operating capacity are charged to expense as incurred. See Note 10 "Operating Segments" in the "Notes to the Consolidated Financial Statements" for a reconciliation of segment profit to consolidated income before cumulative effect of change in accounting principle. The following table reflects our results of operations and maintenance capital for each segment.

Three Months Ended March 31, 2005 and 2004

	Pipeline	GMT&S
	(in millions)	
Three Months Ended March 31, 2005[(1)]		
Revenues	$ 247.2	$ 6,426.2
Purchases	(151.7)	(6,369.4)
Field operating costs (excluding LTIP charge)	(34.0)	(29.5)
LTIP charge operations	(0.1)	(0.2)
Segment G&A expenses (excluding LTIP charge)[(2)]	(10.1)	(10.1)
LTIP charge general and administrative	(1.2)	(0.7)
Segment profit	$ 50.1	$ 16.3
SFAS 133 noncash mark-to-market adjustment[(3)]	$	$ (13.4)
Maintenance capital	$ 2.8	$ 1.2
Three Months Ended March 31, 2004[(1)]		
Revenues	$ 189.3	$ 3,631.3
Purchases	(136.7)	(3,572.9)
Field operating costs (excluding LTIP charge)	(19.3)	(18.5)
LTIP charge operations	(0.1)	(0.4)
Segment G&A expenses (excluding LTIP charge)[(2)]	(6.0)	(9.4)
LTIP charge general and administrative	(1.7)	(2.0)
Segment profit	$ 25.5	$ 28.1
SFAS 133 noncash mark-to-market adjustment[(3)]	$	$ 7.5
Maintenance capital	$ 1.4	$ 0.3

(1) Revenues and purchases include intersegment amounts.

(2) Segment G&A reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on the business activities that existed at that time. The proportional allocations by segment require judgement by management and will continue to be based on the business activities that exist during each period.

(3) Amounts related to SFAS 133 are included in revenues and impact segment profit.

Pipeline Operations

As of March 31, 2005, we owned approximately 15,000 miles (of which approximately 13,000 miles are included in our pipeline segment) of active gathering and mainline crude oil pipelines located throughout the United States and Canada. Our activities from pipeline operations generally consist of transporting volumes of crude oil for a fee and third party leases of pipeline capacity (collectively referred to as "tariff activities"), as well as barrel exchanges and buy/sell arrangements (collectively referred to as "pipeline margin activities"). In connection with certain of our merchant activities conducted under our gathering and marketing business, we are also shippers on certain of our own pipelines. These transactions are conducted at published tariff rates and eliminated in consolidation. Tariffs and other fees on our pipeline systems vary by receipt point and delivery point. The segment profit generated by our tariff and other fee-related activities depends on the volumes transported on the pipeline and the level of the tariff and other fees charged as well as the fixed and variable field costs of operating the pipeline. Segment profit from our pipeline capacity leases, barrel exchanges and buy/sell arrangements generally reflect a negotiated amount.

The following table sets forth our operating results from our Pipeline Operations segment for the periods indicated:

	Three months ended March 31,	
	2005	2004
	(in millions)	
Operating Results[1]		
Revenues		
Tariff activities	$ 89.6	$ 47.0
Pipeline margin activities[2]	157.6	142.3
Total pipeline operations revenues	247.2	189.3
Costs and Expenses		
Pipeline margin activities purchases	(151.7)	(136.7)
Field operating costs (excluding LTIP charge)	(34.0)	(19.3)
LTIP charge operations	(0.1)	(0.1)
Segment G&A expenses (excluding LTIP charge)[3]	(10.1)	(6.0)
LTIP charge general and administrative	(1.2)	(1.7)
Segment profit	$ 50.1	$ 25.5
Maintenance capital	$ 2.8	$ 1.4
Average Daily Volumes (thousands of barrels per day)[4]		
Tariff activities		
All American	54	55
Basin	277	275
Capline[5]	160	54
West Texas/New Mexico Area Systems[6]	401	209
Canada	268	240
Other	494	143
Total tariff activities	1,654	976
Pipeline margin activities	75	72
Total	1,729	1,048

(1) Revenues and purchases include intersegment amounts.

(2) Includes revenues associated with buy/sell arrangements of $33.5 million and $46.4 million for the quarters ended March 31, 2005 and 2004, respectively. Volumes associated with these arrangements were approximately 11,500 barrels per day and 16,800 barrels per day for the quarters ended March 31, 2005 and 2004, respectively.

(3) Segment G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on the business activities that existed at that time. The proportional allocations by segment require judgment by management and will continue to be based on the business activities that exist during each period.

(4) Volumes associated with acquisitions represent total volumes transported for the number of days we actually owned the assets divided by the number of days in the period.

(5) Capline volumes averaged approximately 160,000 barrels per day for March 2004, which is the only month during the first quarter of 2004 in which we owned the system.

(6) The aggregate of ten systems in the West Texas/New Mexico area.

Total revenues from our pipeline operations were approximately $247.2 million and $189.3 million for the three months ended March 31, 2005 and 2004, respectively. An increase in revenues from tariff activities accounted for $42.6 million of the increase (see discussion below). Revenues from our margin activities increased approximately $15.3 million between the periods as a decrease in buy/sell volumes was offset by higher average prices for crude oil sold and transported on our SJV gathering system. Because the barrels that we buy and sell are generally indexed to the same pricing indices, revenues and purchases will increase and decrease with changes in market prices without significant changes to our margins related to those purchases and sales.

Increases in segment profit, our primary measure of segment performance, were driven by the following:

Increased volumes and related tariff revenues The increase in volumes and related tariff revenues is primarily related to the Link acquisition and other acquisitions completed during 2004.

Increased revenues from our loss allowance oil Increased volumes and higher crude oil prices in the first quarter of 2005 as compared to the first quarter of 2004 (the NYMEX average was $49.88 for the first quarter of 2005 compared to $35.21 for the first quarter of 2004) have resulted in increased revenues related to loss allowance oil.

Increased field operating costs Our continued growth, primarily from the Link acquisition and other acquisitions completed during 2004 is the principal driver of the increase in field operating costs of $14.7 million to $34.1 million for the first quarter of 2005. The increased costs are primarily related to (i) payroll and benefits, (ii) emergency response and environmental remediation of pipeline releases and (iii) utilities.

Increased segment G&A expenses The increase in segment G&A expenses in the first quarter of 2005 is primarily related to the Link acquisition coupled with the percentage of indirect costs allocated to the pipeline operations segment increasing in the 2005 period as our pipeline operations have grown in relation to our GMT&S segment.

As discussed above, the increase in pipeline operations segment profit is largely related to our acquisition activities. We completed a number of acquisitions during the last nine months of 2004 that have impacted the results of operations herein. The following presentation helps summarize the impact of recent acquisitions and expansions on volumes and revenues related to our tariff activities.

	Three Months Ended March 31,			
	2005		2004	
	Revenues	Volumes	Revenues	Volumes
	(volumes in thousands of barrels per day and revenues in millions)			
Tariff activities revenues[1][2][3]				
2005 acquisitions/expansions	$ 2.0	50	$	
2004 acquisitions/expansions	38.0	696	3.3	90
All other pipeline systems	49.6	908	43.7	886
Total tariff activities	$ 89.6	1,654	$ 47.0	976

(1) Revenues include intersegment amounts.

(2) Volumes associated with acquisitions represent total volumes transported for the number of days we actually owned the assets divided by the number of days in the period.

(3) To the extent there has been an expansion to one of our existing pipeline systems, any incremental revenues and volumes are included in the results for the period that pipeline was acquired. For new pipeline systems that we construct, incremental revenues and volumes are included in the period the

system became operational.

Average daily volumes from our tariff activities increased approximately 70% to approximately 1.7 million barrels per day and revenues from our tariff activities increased over 90% to $89.6 million.

The increase in the first quarter of 2005 is predominately related to the inclusion of pipeline systems acquired in 2004:

- 389,000 barrels per day and $26.0 million of revenues from the pipelines acquired in the Link acquisition,
- 291,000 barrels per day and $10.9 million of revenues from the pipelines acquired in the Capline acquisition, and
- 16,000 barrels per day and $1.1 million of revenues from other businesses acquired in the last nine months of 2004.

Revenues from all other pipeline systems also increased in the first quarter of 2005, along with a slight increase in volumes. The increase in revenues is related to several items including (i) increased tariff rates on certain of our systems, partially related to the quality of crude oil shipped, (ii) the appreciation of Canadian currency (the Canadian to U.S. dollar exchange rate appreciated to an average of 1.23 to 1 for the first quarter of 2005 compared to an average of 1.32 to 1 in the first quarter of 2004), and (iii) volume increases on certain of our systems.

Gathering, Marketing, Terminalling and Storage Operations

As of March 31, 2005, we owned approximately 37 million barrels of active above-ground crude oil terminalling and storage facilities, including a crude oil terminalling and storage facility at Cushing, Oklahoma. Cushing, which we refer to as the Cushing Interchange, is one of the largest crude oil market hubs in the United States and the designated delivery point for New York Mercantile Exchange, or NYMEX, crude oil futures contracts. Terminals are facilities where crude oil is transferred to or from storage or a transportation system, such as a pipeline, to another transportation system, such as trucks or another pipeline. The operation of these facilities is called "terminalling." Approximately 14 million barrels of our 37 million barrels of tankage is used primarily in our GMT&S Operations segment and the balance is used in our Pipeline Operations segment.

On a stand-alone basis, segment profit from terminalling and storage activities is dependent on the throughput of volumes, the volume of crude oil stored and the level of fees generated from our terminalling and storage services. Our terminalling and storage activities are integrated with our gathering and marketing activities and thus the level of tankage that we allocate for our arbitrage activities (and therefore not available for lease to third parties) varies throughout crude oil price cycles. This integration enables us to use our storage tanks in an effort to counter-cyclically balance and hedge our gathering and marketing activities. In a contango market (when oil prices for future deliveries are higher than for current deliveries), we use our tankage to improve our gathering margins by storing crude oil we have purchased at lower prices in the current month for delivery at higher prices in future months. In a backwardated market (when oil prices for future deliveries are lower than for current deliveries), we use less storage capacity, but increased marketing margins (premiums for prompt delivery) provide an offset to this reduced cash flow. We believe that this combination of our terminalling and storage activities and gathering and marketing activities provides a counter-cyclical balance that has a stabilizing effect on our results of operations and cash flows.

Our revenues from gathering and marketing activities reflect the sale of gathered and bulk-purchased crude oil and LPG volumes, plus the sale of additional barrels exchanged through buy/sell arrangements entered into to supplement the margins of the gathered and bulk-purchased volumes. Because the commodities that we buy and sell are generally indexed to the same pricing indices for both the purchase and the sale, revenues and costs related to purchases will increase and decrease with changes in market prices. However, the margins related to those purchases and sales will not necessarily have corresponding increases and decreases. For example, our revenues increased approximately 77% in the first quarter of 2005 compared to the first quarter of 2004, while our segment profit decreased almost 42% in the same period. This decrease is related to the impact of the SFAS 133 noncash mark-to-market adjustment which resulted in a decrease in segment profit of 74% (see discussion below).

Revenues from our GMT&S operations were approximately $6.4 billion and $3.6 billion for the quarters ended March 31, 2005 and 2004, respectively. Revenues and costs related to purchases for the 2005 period were impacted by higher average prices and higher volumes as compared to the 2004 period. Approximately 70% of the increase in revenues resulted from higher average prices in the 2005 period and the remainder was attributable to increased sales volumes. The average NYMEX price for crude oil was $49.88 per barrel and $35.21 per barrel for the quarter ended March 31, 2005 and 2004, respectively.

Generally, we expect our segment profit to increase or decrease directionally with increases or decreases in lease gathered volumes and LPG sales volumes. Although we believe that the combination of our lease gathering business and our storage assets provides a counter-cyclical balance that provides stability in our margins, these margins are not fixed and may vary from period to period. In order to evaluate the performance of this segment, management focuses on the following metrics: (i) segment profit (ii) crude oil lease gathered volumes and LPG sales volumes and (iii) segment profit per barrel calculated on these volumes. The following table sets forth our operating results from our GMT&S Operations segment for the comparative periods indicated:

	Three months ended March 31,	
	2005	**2004**
	(in millions, except per barrel amounts)	
Operating Results[1]		
Revenues[2][4]	$ 6,426.2	$ 3,631.3
Purchases and related costs	(6,369.4)	(3,572.9)
Field operating costs (excluding LTIP charge)	(29.5)	(18.5)
LTIP charge operations	(0.2)	(0.4)
Segment G&A expenses (excluding LTIP charge)[3]	(10.1)	(9.4)
LTIP charge general and administrative	(0.7)	(2.0)
Segment profit[4]	$ 16.3	$ 28.1
SFAS 133 noncash mark-to-market adjustment[4]	$ (13.4)	$ 7.5
Maintenance capital	$ 1.2	$ 0.3
Segment profit per barrel[5]	$ 0.26	$ 0.60
Average Daily Volumes (thousands of barrels per day)[6]		
Crude oil lease gathering	622	460
LPG sales	84	59

(1) Revenues and purchases and related costs include intersegment amounts.

(2) Includes revenues associated with buy/sell arrangements of $3,419.0 million and $1,834.9 million for the quarters ended March 31, 2005 and 2004, respectively. Volumes associated with these arrangements were approximately 855,000 barrels per day and 597,000 barrels per day for the quarters ended March 31, 2005 and 2004, respectively. The previously referenced amounts include certain estimates based on management's judgment; such estimates are not expected to have a material impact on the balances.

(3) Segment G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on the business activities that existed at that time. The proportional allocations by segment require judgment by management and will continue to be based on the business activities that exist during each period.

(4) Amounts related to SFAS 133 are included in revenues and impact segment profit.

(5) Calculated based on crude oil lease gathered barrels and LPG sales barrels.

(6) Volumes associated with acquisitions represent total volumes transported for the number of days we actually owned the assets divided by the number of days in the period.

Segment profit decreased 42% to $16.3 million for the first quarter of 2005 as compared to the first quarter of 2004. The primary reason for the decrease from quarter to quarter is the impact of our noncash mark-to-market adjustment for open derivative instruments pursuant to SFAS 133. The noncash mark-to-market adjustment was a net loss of $13.4 million in the current quarter compared to a net gain of $7.5 million in the first quarter of 2004. This adjustment resulted in a decrease in segment profit of 74%. The primary components of the noncash adjustment in the first quarter of 2005 were:

- A decrease in the mark-to-market of approximately $4.6 million resulting from the change in fair value for option and futures contracts that serve to reduce our lease gathering and tankage business exposures. Because the tankage arrangements will not necessarily result in physical delivery, they are not eligible for hedge accounting treatment under SFAS 133. In addition, because our option activity often involves option sales, these also do not receive hedge accounting treatment. While these derivatives do not qualify for hedge accounting, their purpose is to mitigate risk associated with our physical assets in our storage and terminalling activities and contractual arrangements in our lease gathering activities.

- A decrease in the mark-to-market resulting from the settlement of approximately $6.8 million of derivatives relating to strategies that were included in our mark-to-market adjustment at December 31, 2004. These positions primarily related to options and futures contracts associated with our gathering and tankage business exposures.

- A decrease in the mark-to-market of approximately $2.6 million resulting from the change in fair value of our Canadian and LPG derivative contracts, which do not consistently qualify for hedge accounting because the correlations tend to fluctuate; and

- An increase in the mark-to-market of $0.6 million primarily related to the change in fair value of certain derivative instruments used to minimize the risk of unfavorable changes in exchange rates.

The other primary drivers of current quarter results were:

- Increased crude oil lease gathered volumes and LPG sales volumes The crude oil volumes gathered from producers, using our assets or third-party assets, have increased by approximately 35% to 622,000 barrels per day for the first quarter of 2005. The increase is primarily related to the Link acquisition. In addition, we marketed 84,000 barrels per day of LPG during the first quarter of 2005 compared to 59,000 barrels per day in the first quarter of 2004.

- Favorable market conditions During the first quarter of 2005, market conditions were favorable for this segment and were characterized by relatively strong contango market conditions throughout the quarter as well as reasonably high volatility and wide differentials on various grades of crude oil. The NYMEX benchmark price of crude ranged from $41.25 to $57.60 during the quarter. This volatile market allowed us to optimize and enhance the margins of both our gathering and marketing assets and our terminalling and storage assets at different times during the quarter. Also positively impacting our results were increased receipts of foreign crude oil movements at our facilities. The market conditions in the first quarter of 2004 were also favorable as there was relatively high volatility and strong backwardation throughout the quarter.

During the first quarter of 2004, the NYMEX benchmark price of crude ranged from $32.20 to $38.50.

Increased tankage used in our GMT&S Operations The positive impact of the favorable market conditions discussed above was further enhanced by the increase in the amount of tankage used in our GMT&S Operations to approximately 14 million barrels in the first quarter of 2005 as compared to 11.0 million barrels in the first quarter of 2004.

Impact of change in Canadian dollar to U.S. dollar exchange rate The first quarter of 2005 includes a foreign exchange loss of $0.8 million. The loss is related to the impact of changes in the Canadian dollar to U.S. dollar exchange rate on net U.S. dollar denominated liabilities in our Canadian subsidiary.

Increased field operating costs Our continued growth, primarily from the Link acquisition is the primary driver of the increase in field operating costs for the 2005 period as compared to the 2004 period.

The impact of the items discussed above resulted in segment profit per barrel (calculated based on our lease gathered crude oil and LPG barrels) of $0.26 per barrel for the quarter ended March 31, 2005, compared to $0.60 for the quarter ended March 31, 2004. The SFAS 133 noncash mark-to-market adjustment had a negative $0.21 segment profit per barrel impact in the first quarter of 2005 compared to a positive $0.16 segment profit per barrel impact in the first quarter of 2004.

Other Expenses

Depreciation and Amortization

Depreciation and amortization expense was $19.1 million for the three months ended March 31, 2005, compared to $13.1 million for the three months ended March 31, 2004. The increase relates primarily to the assets from our 2004 acquisitions being included for the full quarter in 2005 versus only a part or none of the quarter in 2004. Additionally, several capital projects were completed during mid-to-late 2004 that were not included in first quarter 2004 depreciation expense. Amortization of debt issue costs was $0.6 million and $0.5 million in the first quarter of 2005 and 2004, respectively.

Interest Expense

The amount of interest expense we recognize is primarily impacted by:

- our average debt balances,

- the level and maturity of fixed rate debt, and

- interest rates associated therewith, market interest rates and our interest rate hedging activities on floating rate debt.

During the first quarter of 2005, our average debt balance was approximately $1.0 billion, compared to an average balance of approximately $0.6 billion for the first quarter of 2004. The following table summarizes the components of these balances:

	For the three months ended March 31,	
	2005	2004
	(average amount outstanding, in millions)	
Fixed rate senior notes[1]	$ 800	$ 450
Borrowings under our revolving credit facilities	211	149
Total	$ 1,011	$ 599

(1) Face amount of senior notes, exclusive of discounts.

The higher average debt balance in the 2005 period was primarily related to the portion of our acquisitions that were not refinanced with equity, coupled with borrowings related to other capital projects. Our financial growth strategy is to fund our acquisitions using a balance of debt and equity. Our weighted average interest rate, excluding commitment and other fees, was approximately 6.1% for both periods.

The net impact of the items discussed above was an increase in interest expense in the first quarter of 2005 of approximately $5.0 million to a total of $14.6 million. This increase is primarily related to the rise in our average debt balance, partially offset by an increase in interest capitalized.

Interest costs attributable to borrowings for stored inventory are included in our GMT&S segment profit for purposes of matching those costs with the profits realized on storing crude oil. These borrowings are primarily under our senior secured hedged inventory facility. These costs were approximately $3.4 million and $0.1 million for the quarters ended March 31, 2005 and 2004, respectively.

Outlook

This "Outlook" section and the section captioned "Forward Looking Statements and Associated Risks" identify certain matters of risk and uncertainty that may affect our financial performance and results of operations in the future.

Ongoing Acquisition Activities. Consistent with our business strategy, we are continuously engaged in discussions with potential sellers regarding the possible purchase by us of transportation, gathering, terminalling or storage assets and related businesses. These acquisition efforts often involve assets which, if acquired, would have a material effect on our financial condition and results of operations. In an effort to prudently and economically leverage our asset base, knowledge base and skill sets, management has also expanded its efforts to encompass businesses that are closely related to, or significantly intertwined with, the crude oil business. We can give no assurance that our current or future acquisition efforts will be successful or that any such acquisition will be completed on terms considered favorable to us.

As a result of several factors including the tight supply and demand relationship for crude oil world-wide, we believe the crude oil market will continue to be volatile and subject to frequent short-term swings in market prices and shifts in market structure. Over the last seven months, crude oil prices ranged from a low of around $40.00 per barrel to a high of approximately $58.00 per barrel. During that same period, the spread between the futures contracts in the first two months ranged from nearly $1.00 backwardated to as much as $1.90 per barrel contango. While there can be no assurance that such volatile conditions will not have an unanticipated adverse effect on the partnership in the future, we believe the strategic nature of our asset base and our complementary business model position the partnership to benefit from such market conditions, subject to a number of inherent business risks, including our maintaining an attractive credit rating and our continuing ability to receive open credit from our suppliers and trade counter-parties.

Based on this outlook, we increased the capacity of our senior unsecured credit facility and intend to take various actions to further increase our liquidity and ensure that we are positioned to prudently optimize the use of our asset base in the event that prices rise significantly (see discussion in "Liquidity" below). These steps may include one or more of the following actions: increasing the size of our hedged inventory facility; accessing the long-term debt capital markets, and thus increasing the availability under our outstanding credit facility; and/or the issuance of equity.

Liquidity and Capital Resources

Liquidity

Cash generated from operations and our credit facilities are our primary sources of liquidity. At March 31, 2005, we had a working capital deficit of approximately $115.5 million, approximately $320.5 million of availability under our committed revolving credit facilities and no unused capacity under our uncommitted hedged inventory facility (see "Capital Resources" below). Usage of the credit facilities is subject to compliance with covenants. We believe we are currently in compliance with all covenants.

Capital Resources

In February 2005, we issued 575,000 common units to a subsidiary of Vulcan Energy Corporation. The sale price for the common units was $38.13 per unit resulting in net proceeds, including the general partner's proportionate capital contribution and expenses associated with the sale, of approximately $22.3 million. We intend to use the net proceeds from the private placement to fund a portion of our 2005 expansion capital program. Pending the incurrence of such expenditures, the net proceeds were used to repay indebtedness under our revolving credit facilities.

In April 2005, we amended our senior secured hedged inventory facility to increase the capacity under the facility from $425 million to $500 million. We are in the process of negotiating an additional expansion of this facility to increase its capacity by up to $300 million. In addition, in May 2005, we amended our senior unsecured credit facility to increase the capacity from $750 million to $900 million and increased the sub-facility for Canadian borrowings to $360 million. The amended facility can be expanded to $1.25 billion.

We believe that we have sufficient liquid assets, cash flow from operations and borrowing capacity under our credit agreements to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures. However, we are subject to business and operational risks that could adversely affect our cash flow. A material decrease in our cash flows would likely produce an adverse effect on our borrowing capacity.

Cash Flows

	Three Months Ended March 31,	
	2005	2004
	(in millions)	
Cash provided by (used in):		
Operating activities	$ (271.8)	$ 133.0
Investing activities	(61.7)	(155.9)
Financing activities	342.6	(21.1)

Operating Activities. The primary drivers of our cash flow from operations are (i) the collection of amounts related to the sale of crude oil and LPG and the transportation of crude oil for a fee and (ii) the payment of amounts related to the purchase of crude oil and LPG and other expenses, principally field operating costs and general and administrative expenses. The cash settlement from the purchase and sale of crude oil during any particular month typically occurs within thirty days from the end of the month, except in the months that we store inventory because of contango market conditions or in months that we increase linefill. The storage of crude oil in periods of a contango market can have a material impact on our cash flows from operating activities for the period we pay for and store the crude oil and the subsequent period that we receive proceeds from the sale of the crude oil. When we store the crude oil, we borrow on our credit facilities to pay for the crude oil so the impact on operating cash flow is negative. Conversely, cash flow from operating activities increases in the period we collect the cash from the sale of the stored crude oil. In addition, our cash flow from operating activities is also impacted by the level of LPG inventory stored at period end. Cash flow used in operating activities was $271.8 million in 2005. Cash flow provided by operating activities was $133.0 million in 2004.

Cash flows from operating activities in 2005 reflects the purchase and storage of crude oil because of contango market conditions. During the first quarter, we purchased crude oil for storage. These purchases had a negative impact on cash flows from operating activities when the invoices for the crude oil were paid. The proceeds we received from our credit facilities to pay for the crude oil while stored are shown as financing activities in the cash flow statement. As such, until we deliver the crude oil and receive payment from our customers, operating activities in the cash flow statement will be negatively impacted by this activity. Crude oil stored is hedged against price risk.

Investing Activities. Net cash used in 2005 was $61.7 million and was predominantly related to additions to property and equipment comprised of (i) $15.4 million paid for our Trenton pipeline expansion, (ii) $10.2 million paid for our Cushing to Broome pipeline expansion, (iii) $3.1 million paid for our Cushing Phase V expansion, and (iv) various other projects of approximately $21.3 million. Additionally, approximately $13.5 million was paid for various acquisitions. Net cash used in 2004 was $155.9 million and was primarily comprised of (i) $142.3 million paid for the Capline and Capwood Pipeline Systems acquisition (a deposit had been paid in December 2003) and (ii) $13.3 million paid for additions to property and equipment, including approximately $3.4 million related to the Cushing Phase IV expansion.

Financing Activities. Cash provided by financing activities in 2005 was approximately $342.6 million, primarily consisting of:

- approximately $22.3 million of proceeds from a private placement of common units,
- net short and long-term borrowings under our revolving credit facility of approximately $23.5 million,

- net borrowings under our short-term letter of credit and hedged inventory facility of approximately $344.6 million for the purchase of crude oil inventory that was stored (see "Operating Activities" above), and

- $45.0 million of distributions paid to common unitholders and the general partner.

Cash provided by financing activities in 2004 was approximately $21.1 million, primarily consisting of:

- net short and long-term borrowings under our revolving credit facility of approximately $157.5 million used primarily to fund the purchase price of the Capline acquisition,

- net repayments under our short-term letter of credit and hedged inventory facility of approximately $100.5 million resulting from the collection of receivables related to prior year sales of inventory that was stored because of contango market conditions, and

- $35.2 million of distributions paid to common unitholders and the general partner.

Credit Facilities and Long Term Debt

In May 2005, we expanded the amount that we may borrow under our two credit facilities by $450 million. These modifications are part of our proactive effort to maintain significant liquidity and to position ourselves to continue to optimize our extensive and strategically located asset base in a high crude oil price environment. We increased the aggregate capacity under our senior unsecured credit facility from $750 million to $900 million. The facility includes a sub-facility for Canadian borrowings that was increased from $300 million to $360 million. The credit facility may be further increased to an aggregate capacity of $1.25 billion at our option and subject to our obtaining additional commitments from lenders. In addition, our hedged inventory facility was increased from $500 million to $800 million. The hedged inventory facility is an uncommitted working capital facility, which is used to finance the purchase of hedged crude oil inventory for storage when market conditions warrant. Borrowings under our hedged inventory facility are secured by the inventory purchased under the facility and the associated accounts receivable, and are repaid from the proceeds from the sale of the inventory.

A default under our credit facility would permit the lenders to accelerate the maturity of the outstanding debt. As long as we are in compliance with our credit agreements, our ability to make distributions of available cash is not restricted. We are currently in compliance with the covenants contained in our credit agreements and indentures.

Contingencies

See Note 9 "Commitments and Contingencies" in "Notes to the Consolidated Financial Statements."

Commitments

Contractual Obligations. In the ordinary course of doing business we purchase crude oil and LPG from third parties under contracts, the majority of which range in term from thirty-day evergreen to three years. We establish a margin for these purchases by entering into various types of physical and financial sale and exchange transactions through which we seek to maintain a position that is substantially balanced between crude oil and LPG purchases and sales and future delivery obligations. The table below includes purchase obligations related to these activities. Where applicable the amounts presented represent the net obligations associated with buy/sell contracts and those subject to a net settlement arrangement with the counterparty. We do not expect to use a significant amount of internal capital to meet these obligations, as the obligations will be funded by corresponding sales to credit worthy entities.

The following table includes our best estimate of the amount and timing of these payments as well as others due under the specified contractual obligations as of March 31, 2005.

	2005	2006	2007	2008	2009	Thereafter
	(in millions)					
Long-term debt and interest payments[1]	$ 40.3	$ 53.8	$ 53.8	$ 53.8	$ 352.9	$ 799.7
Leases[2]	13.4	14.0	11.5	8.9	7.8	48.0
Capital expenditure obligations	23.4					
Other long-term liabilities[3]	2.8	7.4	5.5	1.1	0.6	2.5
Subtotal	79.9	75.2	70.8	63.8	361.3	850.2
Crude oil and LPG purchases[4]	1,419.0	132.4	114.7	114.7	93.1	
Total	$ 1,498.9	$ 207.6	$ 185.5	$ 178.5	$ 454.4	$ 850.2

(1) Includes debt service payments, interest payments due on our senior notes, interest payments due on the long-term portion of our revolving credit facility currently outstanding and the commitment fee on the portion of our revolving credit facility that is currently not utilized. The interest amount calculated on the long-term portion of our revolving credit facility is based on the assumption that the amount outstanding and the interest rate charged both remain at their current levels.

(2) Leases are primarily for office rent and trucks used in our gathering activities.

(3) Excludes approximately $12.2 million non-current liability related to SFAS 133 which are included in crude oil and LPG purchases.

(4) Amounts are based on estimated volumes and market prices. The actual physical volume purchased and actual settlement prices may vary from the assumptions used in the table. Uncertainties involved in these estimates include levels of production at the wellhead, weather conditions, changes in market prices and other conditions beyond our control.

Letters of Credit. In connection with our crude oil marketing, we provide certain suppliers and transporters with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the crude oil is purchased. Generally, these letters of credit are issued for up to seventy-day periods and are terminated upon completion of each transaction. At March 31, 2005, we had outstanding letters of credit under our various facilities of approximately $174.5 million.

Quantitative and Qualitative Disclosures About Market Risks

The following should be read in conjunction with Quantitative and Qualitative Disclosures About Market Risks included in Item 7A in our 2004 Form 10-K. There have not been any material changes in that information other than those discussed below.

Commodity Price Risk

All of our open commodity price risk derivatives at March 31, 2005 were categorized as non-trading. The fair value of these instruments and the change in fair value that would be expected from a 10 percent price decrease are shown in the table below:

	Fair Value	Effect of 10% Price Decrease
	(in millions)	
Crude oil:		
Futures contracts	$ (30.6)	$ (37.9)
Swaps and options contracts	$ (11.5)	$ 3.8
LPG:		
Swaps and options contracts	$ 0.8	$ (0.8)

Interest Rate Risk

We utilize both fixed and variable rate debt, and are exposed to market risk due to the floating interest rates on our credit facilities. Therefore, from time to time we utilize interest rate swaps and collars to hedge interest obligations on specific debt issuances, including anticipated debt issuances. The table below presents principal payments and the related weighted average interest rates by expected maturity dates for variable rate debt outstanding at March 31, 2005. The 7.75% senior notes issued during 2002, the 5.625% senior notes issued during 2003, the 4.75% senior notes issued during 2004, and the 5.88% senior notes issued during 2004 are fixed rate notes and their interest rates are not subject to market risk. Our variable rate debt bears interest at LIBOR, prime or the bankers acceptance plus the applicable margin. The average interest rates presented below are based upon rates in effect at March 31, 2005. The carrying values of the variable rate instruments in our credit facilities approximate fair value primarily because interest rates fluctuate with prevailing market rates.

	Expected Year of Maturity						
	2005	2006	2007	2008	2009	Thereafter	Total
	(in millions)						
Liabilities:							
Short-term debt variable rate	$ 555.0	$	$	$	$	$	$ 555.0
Average interest rate	3.5%						3.5%
Long-term debt variable rate	$	$	$	$	$ 125.0	$	$ 125.0
Average interest rate					3.7%		3.7%

BUSINESS

General

We are a publicly traded Delaware limited partnership, formed in 1998 and engaged in interstate and intrastate crude oil transportation, and crude oil gathering, marketing, terminalling and storage, as well as the marketing and storage of liquefied petroleum gas and natural gas related petroleum products. We refer to liquefied petroleum gas and natural gas related petroleum products collectively as "LPG." We have an extensive network of pipeline transportation, storage and gathering assets in key oil producing basins and at major market hubs in the United States and Canada. Our operations can be categorized into two primary business activities:

- *Crude Oil Pipeline Transportation Operations*. As of March 31, 2005, we owned approximately 15,000 miles of active gathering and mainline crude oil pipelines located throughout the United States and Canada, of which approximately 13,000 miles are included in our pipeline segment. Our activities from pipeline operations generally consist of transporting crude oil for a fee, third party leases of pipeline capacity, barrel exchanges and buy/sell arrangements.

- *Gathering, Marketing, Terminalling and Storage Operations*. As of March 31, 2005, we owned approximately 37 million barrels of active above ground crude oil terminalling and storage facilities, including approximately 23 million barrels of tankage that are associated with our pipeline operations within our pipeline segment. These facilities include a crude oil terminalling and storage facility at Cushing, Oklahoma. Cushing, which we refer to in this report as the Cushing Interchange, is one of the largest crude oil market hubs in the United States and the designated delivery point for NYMEX crude oil futures contracts. We utilize our storage tanks to counter-cyclically balance our gathering and marketing operations and to execute various hedging strategies to stabilize profits and reduce the negative impact of crude oil market volatility. Our terminalling and storage operations also generate revenue at the Cushing Interchange and our other locations through a combination of storage

  and throughput charges to third parties. We also own approximately 1.8 million barrels of LPG storage. Our gathering and marketing operations include:

  - the purchase of U.S. and Canadian crude oil at the wellhead and the bulk purchase of crude oil at pipeline and terminal facilities, as well as foreign cargoes;

  - the transportation of crude oil on trucks, barges and pipelines;

  - the subsequent resale or exchange of crude oil at various points along the crude oil distribution chain; and

  - the purchase of LPG from producers, refiners and other marketers, the storage of LPG at storage facilities owned by us or third parties and the sale of LPG to wholesalers, retailers and industrial end users.

Business Strategy

Our principal business strategy is to capitalize on the regional crude oil supply and demand imbalances that exist in the United States and Canada by combining the strategic location and distinctive capabilities of our transportation and terminalling assets with our extensive marketing and distribution expertise to generate sustainable earnings and cash flow.

We intend to execute our business strategy by:

- increasing and optimizing throughput on our existing pipeline and gathering assets and realizing cost efficiencies through operational improvements;

utilizing our Cushing Terminal and our other assets to service the needs of refiners and to profit from merchant activities that take advantage of crude oil pricing and quality differentials;

utilizing assets we have recently acquired along the Gulf Coast and our Cushing Terminal to increase our presence in the importation of foreign crude through Gulf of Mexico receipt facilities to U.S. refiners;

- selectively pursuing strategic and accretive acquisitions of crude oil transportation assets, including pipelines, gathering systems, terminalling and storage facilities and other assets that complement our existing asset base and distribution capabilities;

- optimizing and expanding our Canadian operations and our presence in certain areas of the U.S. to take advantage of anticipated increases in the volume and qualities of crude oil produced in these areas as well as increased foreign crude import activities in the Gulf Coast area; and

- prudently and economically leveraging our asset base, knowledge base and skill sets to participate in energy businesses that are closely related to, or significantly intertwined with, the crude oil business.

To a lesser degree, we also engage in a similar business strategy with respect to the wholesale marketing and storage of LPG.

Financial Strategy

Targeted Credit Profile

We believe that a major factor in our continued success is our ability to maintain a competitive cost of capital and access to the capital markets. We have consistently communicated to the financial community our intention to maintain a strong credit profile that we believe is consistent with an investment grade credit rating. We have targeted a general credit profile with the following attributes:

- an average long-term debt-to-total capitalization ratio of approximately 55% or less;

- an average long-term debt-to-EBITDA ratio of approximately 3.5x or less (EBITDA is earnings before interest, taxes, depreciation and amortization); and,

- an average EBITDA-to-interest coverage ratio of approximately 3.3x or better.

Based on our first quarter 2005 results, we were slightly above our targeted metric for long-term debt-to-EBITDA. In order for us to maintain our targeted credit profile and achieve growth through acquisitions, we intend to fund acquisitions using approximately equal proportions of equity and debt. In certain cases, acquisitions will initially be financed using debt since it is difficult to predict the actual timing of accessing the market to raise equity. Accordingly, from time to time we may be outside the parameters of our targeted credit profile.

Credit Rating

As of May 2005, our senior unsecured rating with Standard & Poors and Moody's Investment Services was BBB- stable and Baa3 stable, respectively, both of which are investment grade. We cannot assure you that these ratings will remain in effect for any given period of time or that one or both of these ratings will not be lowered or withdrawn entirely by a rating agency. Note that a credit rating is not a recommendation to buy, sell or hold securities, and may be revised or withdrawn at any time.

Competitive Strengths

We believe that the following competitive strengths position us to successfully execute our principal business strategy:

- ***Our pipeline assets are strategically located and have additional capacity***. Our primary crude oil pipeline transportation and gathering assets are located in well-established oil producing regions and are connected, directly or indirectly, with our terminalling and storage assets that service major North American refinery and distribution markets where we have strong business relationships. In many instances, these assets are strategically positioned to maximize the value of crude oil by transporting it to major trading locations and premium markets. Certain of our pipeline networks currently possess additional capacity that can accommodate increased demand without significant additional capital investment.

Our Cushing Terminal is strategically located and operationally flexible. Our Cushing Terminal interconnects with the Cushing Interchange's major inbound and outbound pipelines, providing access to both foreign and domestic crude oil. Our Cushing Terminal is one of the most modern large-scale terminalling and storage facilities at the Cushing Interchange, incorporating operational enhancements designed with the ability to safely and efficiently terminal, store, blend and segregate large volumes and multiple varieties of crude oil as well as with extensive environmental safeguards. Since becoming operational in late 1993, we have completed four separate expansion phases, increasing the Cushing Terminal's tankage to 6.3 million barrels. In January 2005, we announced the commencement of our Phase V expansion that will increase the Cushing Terminal's capacity by approximately 1.1 million barrels. The project is expected to be operational in the fourth quarter of 2005. In addition, we own approximately 31 million barrels of above-ground crude oil terminalling and storage assets elsewhere in the United States and Canada that are used in our pipeline operations or that complement our Cushing Terminal and enable us to serve the needs of our customers.

We possess specialized crude oil market knowledge. We believe our business relationships with participants in various phases of the crude oil distribution chain, from crude oil producers to refiners, as well as our own industry expertise, provide us with an extensive understanding of the North American physical crude oil markets.

Our business activities are counter-cyclically balanced. We believe that our terminalling and storage activities and our gathering and marketing activities are counter-cyclical. We believe this balance of activities, combined with our pipeline transportation operations, has a stabilizing effect on our cash flow from operations.

We have the financial flexibility to continue to pursue expansion and acquisition opportunities. We believe we have significant resources to finance strategic expansion and acquisition opportunities, including our ability to issue additional partnership units, to borrow under our credit facilities and to issue additional notes in the long-term debt capital markets. As of March 31, 2005, we had approximately $320.5 million available under our committed credit facilities, subject to covenant compliance.

We have an experienced management team whose interests are aligned with those of our unitholders. Our executive management team has an average of more than 20 years industry experience, with an average of over 15 years with us or our predecessors and affiliates. Members of our senior management team own a 4% interest in our general partner and collectively own approximately 690,000 common units. In addition, through grants of phantom units and options, the senior management team also owns significant contingent equity incentives that generally vest upon achievement of performance objectives, continued service or, in certain cases, both.

Recent Developments

Unitholder Meeting

On January 20, 2005, we held a special meeting of our unitholders. At the meeting, our unitholders approved the following matters:

A proposal to approve (a) a change in the terms of our Class B common units to provide that each Class B common unit is convertible into one of our common units and (b) the issuance of additional common units upon such conversion;

A proposal to approve (a) a change in the terms of our Class C common units to provide that each Class C common Unit is convertible into one of our common units and (b) the issuance of additional common units upon such conversion; and

A proposal to approve the terms of our 2005 Long-Term Incentive Plan, which provides for awards of common units, options to purchase common units and other rights to our employees, officers and directors.

Acquisition Activities

Effective on January 1, 2005, we acquired south Louisiana crude oil pipeline assets from Shell Pipeline Company LLG for approximately $12 million. The primary assets acquired include the

Terrebonne Bay gathering system, the Bay St. Elaine pipeline, the Cocodrie to Houma pipeline, the Gocodrie station, the Golden Meadow gathering system, the Turtle Bayou gathering system and the Patterson station.

On January 31, 2005, we acquired the Joarcam Pipeline System from Joarcam Pipeline, LLG and SES Equities, Ltd. The Joarcam Pipeline System is comprised of approximately 36 miles of 6-inch gathering and mainline crude oil pipelines. The system, which has a current operating capacity of approximately 7,500 barrels per day, originates at Gamrose, Alberta and delivers crude oil into the Enbridge Pipeline at Edmonton.

In March 2005, we acquired the Tulsa Propane Distribution Terminal from Koch Hydrocarbon, LP and the Tulsa Pipeline System from Koch Pipeline Company, L.P. The acquired assets include a 130-mile pipeline capable of transporting approximately 400,000 to 500,000 gallons of propane per day, total storage capacity of approximately 810,000 gallons and two truck loading bays. The pipeline connects the terminal to Koch Hydrocarbon, LP's fractionator in Medford, Oklahoma.

Consistent with our business strategy, we are continuously engaged in discussions with potential sellers regarding the possible purchase by us of assets and operations that are strategic and complementary to our existing operations. Such assets and operations include crude oil related assets and LPG assets, as well as energy assets that are closely related to, or intertwined with, these business lines, and enable us to leverage our asset base, knowledge base and skill sets. Such acquisition efforts involve participation by us in processes that have been made public, involve a number of potential buyers and are commonly referred to as "auction" processes, as well as situations in which we believe we are the only party or one of a very limited number of potential buyers in negotiations with the potential seller. These acquisition efforts often involve assets which, if acquired, would have a material effect on our financial condition and results of operations.

Distribution Increase

On January 25, 2005, we announced a cash distribution of $0.6125 per unit on all outstanding limited partner units. This fourth quarter distribution was paid on February 14, 2005, to unitholders of record at the close of business on February 4, 2005. This distribution equals an annual distribution of $2.45 per unit and represents an increase of approximately 8.9% over the February 2004 distribution and approximately 2.1% over the November 2004 distribution.

On April 22, 2005 we announced a cash distribution of $0.6375 per unit on all outstanding limited partner units. This first quarter distribution was paid on May 13, 2005, to unitholders of record at the close of business on May 3, 2005. This distribution equals an annual distribution of $2.55 per unit and represents an increase of approximately 13.3% over the May 2004 distribution and approximately 4.1% over the February 2005 distribution.

Cushing Terminal Expansion

We have started the Phase V expansion of our Cushing Terminal Facility. Under the Phase V expansion, we will construct approximately 1.1 million barrels of additional tankage at our crude oil storage and terminal facility located in Cushing, Oklahoma. The Phase V project will expand the total capacity of the facility to approximately 7.4 million barrels and, including site preparation and additional manifold modifications, is expected to cost approximately $13 million. We estimate that the new tankage will become operational during the fourth quarter of 2005. Upon completion of the Phase V expansion project, our Cushing Terminal Facility will consist of twenty 270,000 barrel tanks, four 150,000 barrel tanks, fourteen 100,000 barrel tanks and a manifold and pumping system capable of handling up to 800,000 barrels of crude oil throughput per day.

February 2005 Private Placement of Common Units

In February, 2005, we issued 575,000 common units to a subsidiary of Vulcan Energy Corporation. The sale price for the common units was $38.13 per unit resulting in net proceeds, including the general partner's proportionate capital contribution and expenses associated with the sale, of approximately $22.3 million. We intend to use the net proceeds from the private placement to fund a portion of our 2005 expansion capital program. Pending the incurrence of such expenditures, the net proceeds will be used to repay indebtedness under our revolving credit facilities.

Expansion of Credit Facilities

We expanded the amount that we may borrow under our two credit facilities by $450 million. We increased the aggregate capacity under our senior unsecured credit facility from $750 million to $900 million. The facility includes a sub-facility for Canadian borrowings that was increased from $300 million to $360 million. The credit facility may be further increased to an aggregate capacity of $1.25 billion at our option and subject to our obtaining additional commitments from lenders. In addition, our hedged inventory facility was increased from $500 million to $800 million. The hedged inventory facility is an uncommitted working capital facility, which is used to finance the purchase of hedged crude oil inventory for storage when market conditions warrant. Borrowings under our hedged inventory facility are secured by the inventory purchased under the facility and the associated accounts receivable, and are repaid from the proceeds from the sale of the inventory.

Change to Board of Directors

In April, 2005, we announced that John T. Raymond resigned from the board of directors of our general partner, Plains All American GP LLC. Mr. Raymond had served on the board since June 2001. We also announced that Mr. Raymond resigned as CEO of Vulcan Energy Corporation, which owns a 44% interest in Plains All American GP LLC. Mr. Raymond will continue to serve on the board of, and as a non-exclusive consultant to, Vulcan Energy Corporation.

Organizational History

We were formed as a master limited partnership in September 1998 to acquire and operate midstream crude oil businesses and assets. We completed our initial public offering in November 1998. Since June 2001, our 2% general partner interest has been held by Plains AAP, L.P., a Delaware limited partnership. Plains All American GP LLC, a Delaware limited liability company, is Plains AAP, L.P.'s general partner. Unless the context otherwise requires, we use the term "general partner" to refer to both Plains AAP, L.P. and Plains All American GP LLC. Plains AAP, L.P. and Plains All American GP LLC are essentially held by seven owners. See "Security Ownership of Certain Beneficial Owners and Management and Related Unitholders' Matters Beneficial Ownership of General Partner Interest."

Partnership Structure and Management

Our operations are conducted through, and our operating assets are owned by, our subsidiaries. We own our interests in our subsidiaries through two operating partnerships, Plains Marketing, L.P. and Plains Pipeline, L.P. Our Canadian and LPG operations are conducted through Plains Marketing Canada, L.P.

Our general partner, Plains AAP, L.P., is a limited partnership. Our general partner is managed by its general partner, Plains All American GP LLC, which has ultimate responsibility for conducting our business and managing our operations. Plains All American GP LLC is governed by an eight-member board of directors. As amended in July 2004, the limited liability company agreement provides that four directors are designated by the four owners that hold 9% or greater of the outstanding membership interests of Plains All American GP LLC, one director is the Chairman and CEO and three independent directors are elected by majority vote of the membership owners of Plains All American GP LLC. Our general partner does not receive a management fee or other compensation in connection with its management of our business, but it is reimbursed for all direct and indirect expenses incurred on our behalf.

The chart on the next page depicts the current structure and ownership of Plains All American Pipeline, L.P. and certain subsidiaries.

Partnership Structure

Acquisitions

An integral component of our business strategy and growth objective is to acquire assets and operations that are strategic and complementary to our existing operations. Such assets and operations include crude oil related assets and LPG assets, as well as energy assets that are closely related to, or intertwined with, these business lines, and enable us to leverage our asset base, knowledge base and skill sets. We have established a target to complete, on average, $200 million to $300 million in acquisitions per year, subject to availability of attractive assets on acceptable terms. Since 1998, and through December 31, 2004, we have completed numerous acquisitions for an aggregate purchase price of approximately $1.9 billion. In addition, from time to time, we have sold assets that are no longer considered essential to our operations.

The following table summarizes selected acquisitions that we have completed over the past five years:

Acquisition	Date	Description	Approximate Purchase Price (in millions)	
Schaefferstown Propane Storage Facility	August 2004	Storage capacity of approximately 0.5 million barrels of refrigerated propane	$	32
Cal Ven Pipeline System	May 2004	195-miles of gathering and mainline crude oil pipelines in northern Alberta	$	19
Link Energy LLC	April 2004	The North American crude oil and pipeline operations of Link Energy, LLC ("Link")	$	332
Capline and Capwood Pipeline Systems	March 2004	An approximate 22% undivided joint interest in the Capline Pipeline System and an approximate 76% undivided joint interest in the Capwood Pipeline System	$	158
South Saskatchewan Pipeline System	November 2003	A 158-mile mainline crude oil pipeline and 203 miles of gathering lines in Saskatchewan	$	48
ArkLaTex Pipeline System	October 2003	240 miles of crude oil gathering and mainline pipelines and 470,000 barrels of crude oil storage capacity	$	21
Iraan to Midland Pipeline System	June 2003	98-mile mainline crude oil pipeline	$	18
South Louisiana Assets	June 2003 and December 2003	Various terminalling and gathering assets in South Louisiana, including a 100% interest in Atchafalaya Pipeline, L.L.C.	$	18
Iatan Gathering System	March 2003	West Texas crude oil gathering system	$	24
Red River Pipeline System	February 2003	334-mile crude oil pipeline along with 645,000 barrels of crude oil storage capacity	$	19
Shell West Texas Assets	August 2002	Basin Pipeline System, Permian Basin Pipeline System and the Rancho Pipeline System	$	324
Canadian Operations	May/July 2001	The assets of CANPET Energy Group (crude oil and LPG marketing) and substantially all of the Canadian crude oil pipeline, gathering, storage and terminalling assets of Murphy Oil Company Ltd. (560 miles of crude oil and condensate mainlines along with 1.1 million barrels of crude oil storage and terminalling capacity)	$	232

The following is a more in-depth discussion of selected acquisitions completed in 2004:

Schaefferstown Propane Storage Facility

In August 2004, we completed the acquisition of the Schaefferstown Propane Storage Facility from Koch Hydrocarbon, L.P. The total purchase price was approximately $32 million, including transaction costs. In connection with the transaction, the Partnership also acquired an additional $14.2 million of inventory. The transaction was funded through a combination of cash on hand and borrowings under the Partnership's revolving credit facilities. The storage facility is located approximately 65 miles northwest of Philadelphia near Schaefferstown, Pennsylvania, and has the capacity to store approximately 0.5 million barrels of refrigerated propane. In addition, the facility has 19 bullet storage tanks with an aggregate capacity of approximately 14,000 barrels. Propane is delivered to the facility via truck or pipeline and is transported out of the facility by truck. In addition, the transaction also included approximately 61 acres of land and a truck rack. The results of operations and assets from this acquisition have been included in our consolidated financial statements and our gathering, marketing, terminalling and storage operations segment since August 25, 2004.

Cal Ven Pipeline System

On May 7, 2004, we completed the acquisition of the Cal Ven Pipeline System from Cal Ven Limited, a subsidiary of Unocal Canada Limited. The total purchase price was approximately $19 million, including transaction costs. The Cal Ven Pipeline System includes approximately 195 miles of 8-inch and 10-inch gathering and mainline crude oil pipelines. The system is located in northern Alberta and has the ability to deliver crude oil into the Rainbow Pipeline System. The results of operations and assets from this acquisition have been included in our consolidated financial statements and our pipeline operations segment since May 1, 2004.

Link Energy LLC

On April 1, 2004, we completed the acquisition of all of the North American crude oil and pipeline operations of Link Energy LLC ("Link") for approximately $332 million, including $268 million of cash (net of approximately $5.5 million subsequently returned to us from an indemnity escrow account) and approximately $64 million of net liabilities assumed and acquisition-related costs. The Link crude oil business consists of approximately 7,000 miles of active crude oil pipeline and gathering systems, over 10 million barrels of active crude oil storage capacity, a fleet of approximately 200 owned or leased trucks and approximately 2 million barrels of crude oil linefill and working inventory. The Link assets complement our assets in West Texas and along the Gulf Coast and allowed us to expand our presence in the Rocky Mountain and Oklahoma/Kansas regions. The results of operations and assets from this acquisition have been included in our consolidated financial statements and both our pipeline operations and gathering, marketing, terminalling and storage operations segments since April 1, 2004.

Capline and Capwood Pipeline System

In March 2004, we completed the acquisition of all of Shell Pipeline Company LP's ("SPLC") interests in two entities for approximately $158.0 million in cash (including a $15.8 million deposit paid in December 2003) and approximately $0.5 million of transaction and other costs. The principal assets of the entities are: (i) an approximate 22% undivided joint interest in the Capline Pipeline System, and (ii) an approximate 76% undivided joint interest in the Capwood Pipeline System. The Capline Pipeline System is a 633-mile, 40-inch mainline crude oil pipeline originating in St. James, Louisiana, and terminating in Patoka, Illinois. The Capline system is one of the primary transportation routes for crude oil shipped into the Midwestern U.S., accessing over 2.7 million barrels of refining capacity in PADD II. Capline has direct connections to a significant amount of sweet and light sour crude production in the Gulf of Mexico. In addition, with its two active docks capable of handling 600,000-barrel tankers as well as access to LOOP, the Louisiana Offshore Oil Port, the Capline System is a key transporter of both domestic and foreign crude to PADD II. The total system operating capacity is 1.14 million barrels per day, with approximately 248,000 barrels per day subject to the interest acquired. Since we acquired this asset, throughput on the interest we acquired averaged approximately 147,000 barrels per day.

The Capwood Pipeline System is a 57-mile, 20-inch mainline crude oil pipeline originating in Patoka, Illinois, and terminating in Wood River, Illinois. The Capwood system has an operating capacity of 277,000 barrels per day of crude oil. Of that capacity, approximately 211,000 barrels per day are subject to the interest acquired. Since we acquired this asset, throughput on the interest we acquired averaged approximately 120,000 barrels per day. The Capwood System has the ability to deliver crude at Wood River to PADD II refineries and pipelines. Movements on the Capwood system are driven by the volumes shipped on Capline as well as Canadian crude that can be delivered to Patoka via the Mustang Pipeline. Since closing, we have assumed the operatorship of the Capwood system from SPLC.

Ongoing Acquisition Activities

Consistent with our business strategy, we are continuously engaged in discussions with potential sellers regarding the possible purchase by us of assets and operations that are strategic and complementary to our existing operations. Such assets and operations include crude oil related assets and LPG assets, as well as energy assets that are closely related to, or intertwined with, these business lines, and enable us to leverage our asset base, knowledge base and skill sets. Such acquisition efforts involve participation by us in processes that have been made public, involve a number of potential buyers and are commonly referred to as "auction" processes, as well as situations in which we believe we are the only party or one of a very limited number of potential buyers in negotiations with the potential seller. These acquisition efforts often involve assets which, if acquired, would have a material effect on our financial condition and results of operations.

Dispositions

Shutdown and Sale of Rancho Pipeline System

We acquired an interest in the Rancho Pipeline System from Shell in August 2002. The Rancho Pipeline System Agreement dated November 1, 1951, pursuant to which the system was constructed and operated, terminated in March 2003. Upon termination, the agreement required the owners to take the pipeline system, in which we owned an approximate 50% interest, out of service. Accordingly, we notified our shippers and did not accept nominations for movements after February 28, 2003. This shutdown was contemplated at the time of the acquisition and was accounted for under purchase accounting in accordance with SFAS No. 141 "Business Combinations." The pipeline was shut down on March 1, 2003 and a purge of the crude oil linefill was completed in April 2003. In June 2003, we completed transactions whereby we transferred our ownership interest in approximately 241 miles of the total 458 miles of the pipeline in exchange for $4.0 million and approximately 500,000 barrels of crude oil tankage in West Texas. In August 2004, we sold our interest in the remaining portion of the system for approximately $0.9 million, including the assumption by the purchaser of all liabilities typically associated with pipelines of this type. We recognized a gain of approximately $0.6 million on this transaction.

All American Pipeline Linefill Sale and Asset Disposition

In March 2000, we sold the segment of the All American Pipeline that extends from Emidio, California to McCamey, Texas for $129.0 million. Except for minor third-party volumes, one of our subsidiaries, Plains Marketing, L.P., was the sole shipper on this segment of the pipeline since its predecessor acquired the line from the Goodyear Tire & Rubber Company in July 1998. We realized net proceeds of approximately $124.0 million after the associated transaction costs and estimated costs to remove equipment. We used the proceeds from the sale to reduce outstanding debt. We recognized a gain of approximately $20.1 million in connection with the sale.

We had suspended shipments of crude oil on this segment of the pipeline in November 1999. At that time, we owned approximately 5.2 million barrels of crude oil in the segment of the pipeline. We sold this crude oil from November 1999 to February 2000 for net proceeds of approximately $100.0 million, which were used for working capital purposes. We recognized an aggregate gain of approximately $44.6 million, of which approximately $28.1 million was recognized in 2000.

Description of Segments and Associated Assets

Our business activities are conducted through two primary segments, Pipeline Operations and Gathering, Marketing, Terminalling and Storage Operations ("GMT&S"). Our operations are conducted in approximately 40 states in the United States and six provinces in Canada.

Following is a description of the activities and assets for each of our business segments:

Pipeline Operations

As of March 31, 2005, we owned approximately 15,000 miles of active gathering and mainline crude oil pipelines located throughout the United States and Canada. Approximately 13,000 miles of these pipelines are used in our pipeline operations segment with the remainder used in our GMT&S segment. Our activities from pipeline operations generally consist of transporting crude oil for a fee and third-party leases of pipeline capacity, as well as barrel exchanges and buy/sell arrangements.

Substantially all of our pipeline systems are controlled or monitored from one of two central control rooms with computer systems designed to continuously monitor real-time operational data, including measurement of crude oil quantities injected into and delivered through the pipelines, product flow rates, and pressure and temperature variations. The systems are designed to enhance leak detection capabilities, sound automatic alarms in the event of operational conditions outside of pre-established parameters and provide for remote controlled shut-down of pump stations on the pipeline systems. Pump stations, storage facilities and meter measurement points along the pipeline systems are linked by telephone, satellite, radio or a combination thereof to provide communications for remote monitoring and in some instances control, which reduces our requirement for full-time site personnel at most of these locations.

We perform scheduled maintenance on all of our pipeline systems and make repairs and replacements when necessary or appropriate. We attempt to control corrosion of the mainlines through the use of cathodic protection, corrosion inhibiting chemicals injected into the crude stream and other protection systems typically used in the industry. Maintenance facilities containing equipment for pipe repairs, spare parts and trained response personnel are strategically located along the pipelines and in concentrated operating areas. We believe that all of our pipelines have been constructed and are maintained in all material respects in accordance with applicable federal, state, provincial and local laws and regulations, standards prescribed by the American Petroleum Institute, the Canadian Standards Association and accepted industry practice. See " Regulation Pipeline and Storage Regulation."

Major Pipeline Assets

All American Pipeline System

The All American Pipeline is a common carrier crude oil pipeline system that transports crude oil produced from certain outer continental shelf, or OCS, fields offshore California via connecting pipelines to refinery markets in California. The system extends approximately 10 miles along the California coast from Las Flores to Gaviota (24-inch diameter pipe) and continues from Gaviota approximately 126 miles to our station in Emidio, California (30-inch diameter pipe). Between Gaviota and our Emidio Station, the All American Pipeline interconnects with our San Joaquin Valley, or SJV, Gathering System as well as various third-party intrastate pipelines. The system is subject to tariff rates regulated by the FERC.

The All American Pipeline currently transports OCS crude oil received at the onshore facilities of the Santa Ynez field at Las Flores and the onshore facilities of the Point Arguello field located at Gaviota. ExxonMobil, which owns all of the Santa Ynez production, and Plains Exploration and Production Company ("PXP") and other producers that together own approximately 75% of the Point Arguello production, have entered into transportation agreements committing to transport all of their production from these fields on the All American Pipeline. These agreements, which expire in August 2007, provide for a minimum tariff with annual escalations based on specific composite indices. The producers from the Point Arguello field that do not have contracts with us have no other means of transporting their production and, therefore, ship their volumes on the All American Pipeline at the filed tariffs. Volumes attributable to PXP are purchased and sold to a third party under our marketing agreement with PXP before such volumes enter the All American Pipeline. See "Certain Relationships and Related Transactions Transactions with Related Parties General." The third party pays the same tariff as required in the transportation agreements. For 2003 and 2004, the tariffs averaged $1.71 per barrel and $1.81 per barrel, respectively. Effective January 1, 2005, based on the contractual escalator, the average tariff increased to $1.88 per barrel. The agreements do not require these owners to transport a minimum volume.

A significant portion of our revenues less direct field operating costs is derived from the pipeline transportation business associated with these two fields. The relative contribution to our revenues less direct field operating costs from these fields has decreased from approximately 24% in 2000 to 11% in 2004, as we have grown and diversified through acquisitions and organic expansions and as a result of declines in volumes produced and transported from these fields. Since our acquisition in 1998, the volume decline has been substantially offset by an increase in pipeline tariffs. Over the last several years, transportation volumes received from the Santa Ynez and Point Arguello fields have declined from 92,000 and 60,000 average daily barrels, respectively, in 1995 to 44,000 and 10,000 average daily barrels, respectively, for 2004. We expect that there will continue to be natural production declines from each of these fields as the underlying reservoirs are depleted. A 5,000 barrel per day decline in volumes shipped from these fields would result in a decrease in annual pipeline segment profit of approximately $3.2 million, based on a tariff of $1.88 per barrel.

In October 2004, PXP announced that it had successfully completed an initial development well into the Rocky Point field that is accessible from the Point Arguello platforms and that drilling operations are underway on a second development well. If successful, such incremental drilling activity could lead to increased volumes on our All American Pipeline System in future periods. However, we can give no assurance that our volumes transported would increase as a result of this drilling activity.

The table below sets forth the historical volumes received from both of these fields for the past five years:

	Year Ended December 31				
	2004	2003	2002	2001	2000
	(barrels in thousands)				
Average daily volumes received from:					
Point Arguello (at Gaviota)	10	13	16	18	18
Santa Ynez (at Las Flores)	44	46	50	51	56
Total	54	59	66	69	74

Basin Pipeline System

The Basin Pipeline System, in which we own an approximate 87% undivided joint interest, is a primary route for transporting Permian Basin crude oil to Cushing, Oklahoma, for further delivery to Mid-Continent and Midwest refining centers. We acquired the Basin Pipeline System in August 2002. Since acquisition, we have been the operator of the system. The Basin system is a 515-mile mainline, telescoping crude oil system with a capacity ranging from approximately 144,000 barrels per day to 394,000 barrels per day depending on the segment. System throughput (as measured by system deliveries) was approximately 265,000 barrels per day (net to our interest) during 2004. Within the current operating range, a 20,000 barrel per day decline in volumes shipped on the Basin system would result in a decrease in annual pipeline segment profit of approximately $1.8 million.

The Basin system consists of three primary movements of crude oil: (i) barrels are shipped from Jal, New Mexico to the West Texas markets of Wink and Midland, where they are exchanged and/or further shipped to refining centers; (ii) barrels are shipped to the Mid-Continent region on the Midland to Wichita Falls segment and the Wichita Falls to Cushing segment; and (iii) foreign and Gulf of Mexico barrels are delivered into Basin at Wichita Falls and delivered to a connecting carrier or shipped to Cushing for further distribution to Mid-Continent or Midwest refineries. The system also includes approximately 5.8 million barrels (5.0 million barrels, net to our interest) of crude oil storage capacity located along the system.

In 2004, we expanded a 424-mile section of the system extending from Midland, Texas to Cushing, Oklahoma. With the completion of this expansion, the capacity of this section has increased approximately 15%, from 350,000 barrels per day to approximately 400,000 barrels per day. The Basin system is subject to tariff rates regulated by the Federal Energy Regulatory Commission (the "FERC"). TEPPCO Partners, L.P. owns the remaining approximately 13% interest in the system.

Capline/Capwood Pipeline Systems

The Capline Pipeline System, in which we own a 22% undivided joint interest, is a 633-mile, 40-inch mainline crude oil pipeline originating in St. James, Louisiana, and terminating in Patoka, Illinois. The Capline Pipeline System is one of the primary transportation routes for crude oil shipped into the Midwestern U.S., accessing over 2.7 million barrels of refining capacity in PADD II. Capline has direct connections to a significant amount of crude production in the Gulf of Mexico. In addition, with its two active docks capable of handling 600,000-barrel tankers as well as access to LOOP, it is a key transporter of sweet and light sour foreign crude to PADD II. With a total system operating capacity of 1.14 million barrels per day of crude oil, approximately 248,000 barrels per day are subject to our interest. Since we acquired this asset in March 2004, throughput on the interest acquired has averaged approximately 147,000 barrels per day. A 10,000 barrel per day decline in volumes shipped on the Capline system would result in a decrease in annual pipeline segment profit of approximately $1.5 million.

The Capwood Pipeline System, in which we own a 76% undivided joint interest, is a 57-mile, 20-inch mainline crude oil pipeline originating in Patoka, Illinois, and terminating in Wood River, Illinois. The Capwood Pipeline System has an operating capacity of 277,000 barrels per day of crude oil. Of that capacity, approximately 211,000 barrels per day are subject to our interest. The system has the ability to deliver crude oil at Wood River to several other PADD II refineries and pipelines. Movements on the Capwood system are driven by the volumes shipped on Capline as well as Canadian crude that can be delivered to Patoka via the Mustang Pipeline. PAA assumed the operatorship of the Capwood system from SPLC. Since we acquired this asset in March 2004, throughput net to our interest acquired has averaged approximately 120,000 barrels per day.

Our significant pipeline systems are discussed on the previous pages. Following is a tabular presentation of all of our active pipeline assets in the United States and Canada, grouped by geographic location and including the aforementioned major pipeline assets:

Region	Pipeline	Ownership Percentage	Pipeline Mileage	2004 Average Net Volumes
Southwest US	Basin	87.0%	515	265,000
	West Texas Gathering	100.0%	717	80,000
	Permian Basin	100.0%	919	46,000
	Dollarhide	100.0%	24	6,000
	Mesa	8.8%	79	28,000
	Iraan	100.0%	98	23,000
	Iatan	100.0%	360	22,000
	New Mexico	100.0%	1,185	50,000
	Texas	100.0%	1,276	80,000
	Lefors	100.0%	68	2,000
	Merkel	100.0%	128	1,000
Western US	All American	100.0%	136	54,000
	San Joaquin Valley	100.0%	86	74,000
US Rocky Mountains	Butte	22.0%	370	15,000
	North Dakota	100.0%	620	39,000
US Gulf Coast	Sabine Pass	100.0%	33	15,000
	Ferriday	100.0%	570	7,000
	La Gloria	100.0%	114	23,000
	Red River	100.0%	567	12,000
	ArkLaTex	100.0%	161	7,000
	Atchafalaya	100.0%	35	14,000
	Eugene Island	100.0%	66	12,000
	Bridger Lakes	100.0%	17	3,000
	Capline	22.0%	633	123,000
	Capwood/Patoka	76.0%	57	109,000
	Pearsall	100.0%	62	2,000
	Mississippi/Alabama	100.0%	686	29,000
	Southwest Louisiana	100.0%	267	4,000
Central US	Oklahoma	100.0%	1,498	56,000
	Midcontinent	100.0%	1,196	22,000
Canada	Cal Ven	100.0%	177	11,000
	Manito	100.0%	101	71,000
	Milk River	100.0%	11	106,000
	Cactus Lake	14.9%	55	3,000
	Wascana	100.0%	114	9,000
	Wapella	100.0%	79	14,000
	South Sask	100.0%	158	49,000

Gathering, Marketing, Terminalling and Storage Operations

The combination of our gathering and marketing operations and our terminalling and storage operations provides a counter-cyclical balance that has a stabilizing effect on our operations and cash flow. The strategic use of our terminalling and storage assets in conjunction with our gathering and marketing operations generally provides us with the flexibility to maintain our margins irrespective of whether a strong or weak market exists. Following is a description of our activities with respect to this segment.

Gathering and Marketing Operations

Crude Oil. The majority of our gathering and marketing activities are in the geographic locations previously discussed. These activities include:

- purchasing crude oil from producers at the wellhead and in bulk from aggregators at major pipeline interconnects, trading locations as well as foreign cargoes brought in by tanker;
- transporting crude oil on our own proprietary gathering assets and our common carrier pipelines or, when necessary or cost effective, assets owned and operated by third parties;
- exchanging crude oil for another grade of crude oil or at a different geographic location, as appropriate, in order to maximize margins or meet contract delivery requirements; and
- marketing crude oil to refiners or other resellers.

We purchase crude oil from many independent producers and believe that we have established broad-based relationships with crude oil producers in our areas of operations. Gathering and marketing activities involve relatively large volumes of transactions often with lower margins than pipeline and terminalling and storage operations.

The following table shows the average daily volume of our lease gathering and bulk purchases for the past five years:

	Year Ended December 31				
	2004	2003	2002	2001	2000
	(barrels in thousands)				
Lease gathering	589	437	410	348	262
Bulk purchases	148	90	68	46	28
Total volumes per day	737	527	478	394	290

Crude Oil Purchases. We purchase crude oil from producers under contracts, the majority of which range in term from a thirty-day evergreen to three years. In a typical producer's operation, crude oil flows from the wellhead to a separator where the petroleum gases are removed. After separation, the crude oil is treated to remove water, sand and other contaminants and is then moved into the producer's on-site storage tanks. When the tank is approaching capacity, the producer contacts our field personnel to purchase and transport the crude oil to market. We utilize our truck fleet and gathering pipelines as well as third-party pipelines, trucks and barges to transport the crude oil to market. We own or lease approximately 400 trucks used for gathering crude oil.

We currently have a marketing agreement with PXP for certain of its equity crude oil production and that of its subsidiaries. The marketing agreement provides that we will purchase PXP's equity crude oil production for resale at market prices, for which we charge a fee of $0.20 per barrel. For any new contracts for the sale of the crude oil entered into after January 1, 2005, the marketing fee will be adjusted to $0.15 per barrel, subject to further adjustment in November 2007 based upon then existing

market conditions. See "Certain Relationships and Related Transactions Transactions with Related Parties General."

Bulk Purchases. In addition to purchasing crude oil at the wellhead from producers, we purchase crude oil in bulk at major pipeline terminal locations. This oil is transported from the wellhead to the pipeline by major oil companies, large independent producers or other gathering and marketing companies. We purchase crude oil in bulk when we believe additional opportunities exist to realize margins further downstream in the crude oil distribution chain. The opportunities to earn additional margins vary over time with changing market conditions. Accordingly, the margins associated with our bulk purchases will fluctuate from period to period.

Crude Oil Sales. The marketing of crude oil is complex and requires current detailed knowledge of crude oil sources and end markets and a familiarity with a number of factors including grades of crude oil, individual refinery demand for specific grades of crude oil, area market price structures for the different grades of crude oil, location of customers, availability of transportation facilities and timing and costs (including storage) involved in delivering crude oil to the appropriate customer. We sell our crude oil to major integrated oil companies, independent refiners and other resellers in various types of sale and exchange transactions. The majority of these contracts are at market prices and have terms ranging from one month to three years.

We establish a margin for crude oil we purchase by selling crude oil for physical delivery to third-party users, such as independent refiners or major oil companies, or by entering into a future delivery obligation with respect to futures contracts on the NYMEX or over-the-counter. Through these transactions, we seek to maintain a position that is substantially balanced between crude oil purchases and sales and future delivery obligations. From time to time, we enter into various types of sale and exchange transactions including fixed price delivery contracts, floating price collar arrangements, financial swaps and crude oil futures contracts as hedging devices. Except for pre-defined inventory positions, our policy is generally to purchase only crude oil for which we have a market, to structure our sales contracts so that crude oil price fluctuations do not materially affect the segment profit we receive, and to not acquire and hold crude oil, futures contracts or other derivative products for the purpose of speculating on crude oil price changes that might expose us to indeterminable losses. In November 1999, we discovered a significant violation of this policy. As a result, we incurred an aggregate loss of approximately $181 million in unauthorized trading losses, including associated costs and legal expenses.

Crude Oil Exchanges. We pursue exchange opportunities to enhance margins throughout the gathering and marketing process. When opportunities arise to increase our margin or to acquire a grade of crude oil that more closely matches our physical delivery requirement or the preferences of our refinery customers, we exchange physical crude oil with third parties. These exchanges are effected through contracts called exchange or buy-sell agreements. Through an exchange agreement, we agree to buy crude oil that differs in terms of geographic location, grade of crude oil or physical delivery schedule from crude oil we have available for sale. Generally, we enter into exchanges to acquire crude oil at locations that are closer to our end markets, thereby reducing transportation costs and increasing our margin. We also exchange our crude oil to be physically delivered at a later date, if the exchange is expected to result in a higher margin net of storage costs, and enter into exchanges based on the grade of crude oil, which includes such factors as sulfur content and specific gravity, in order to meet the quality specifications of our physical delivery contracts.

Producer Services. Crude oil purchasers who buy from producers compete on the basis of competitive prices and highly responsive services. Through our team of crude oil purchasing representatives, we maintain ongoing relationships with producers in the U.S. and Canada. We believe that our ability to offer high-quality field and administrative services to producers is a key factor in our ability to maintain volumes of purchased crude oil and to obtain new volumes. Field services include efficient gathering capabilities, availability of trucks, willingness to construct gathering pipelines where economically justified, timely pickup of crude oil from tank batteries at the lease or production point, accurate measurement of crude oil volumes received, avoidance of spills and effective management of pipeline deliveries. Accounting and other administrative services include securing division orders (statements from interest owners affirming the division of ownership in crude oil purchased by us), providing statements of the crude oil purchased each month, disbursing production proceeds to interest owners, and calculation and payment of ad valorem and production taxes on behalf of interest owners. In order to compete effectively, we must maintain records of title and division order interests in an accurate and timely manner for purposes of making prompt and correct payment of crude oil production proceeds, together with the correct payment of all severance and production taxes associated with such proceeds.

Liquefied Petroleum Gas and Other Petroleum Products. We also market and store LPG and other petroleum products in the United States and Canada. These activities include:

- purchasing LPG (primarily propane and butane) from producers at gas plants and in bulk at major pipeline terminal points and storage locations;

- transporting the LPG via common carrier pipelines, railcars and trucks to our own terminals and third party facilities for subsequent resale by them to retailers and other wholesale customers; and

- exchanging product to other locations to maximize margins and /or to meet contract delivery requirements.

We purchase LPG from numerous producers and have established long-term, broad based relationships with LPG producers in our areas of operation. We purchase LPG directly from gas plants, major pipeline terminals, refineries and storage locations. Marketing activities for LPG typically consist of smaller volumes and generally higher margin per barrel transactions relative to crude oil.

LPG Purchases. We purchase LPG from producers, refiners, and other LPG marketing companies under contracts that range from immediate delivery to one year in term. In a typical producer's or refiner's operation, LPG that is produced at the gas plant or refinery is fractionated into various components including propane and butane and then purchased by us for movement via tank truck, railcar or pipeline.

In addition to purchasing LPG at gas plants or refineries, we also purchase LPG in bulk at major pipeline terminal points and storage facilities from major oil companies, large independent producers or other LPG marketing companies. We purchase LPG in bulk when we believe additional opportunities exist to realize margins further downstream in our LPG distribution chain. The opportunities to earn additional margins vary over time with changing market conditions. Accordingly, the margins associated with our bulk purchases will fluctuate from period to period.

LPG Sales. The marketing of LPG is complex and requires current detailed knowledge of LPG sources and end markets and a familiarity with a number of factors including the various modes and availability of transportation, area market prices and timing and costs of delivering LPG to customers.

We sell LPG primarily to industrial end users and retailers, and limited volumes to other marketers. Propane is sold to small independent retailers who then transport the product via bobtail truck to residential consumers for home heating and to some light industrial users such as forklift operators. Butane is used by refiners for gasoline blending and as a diluent for the movement of conventional heavy oil production. Butane demand for use as heavy oil diluent has increased as supplies of Canadian condensate have declined.

We establish a margin for propane by transporting it in bulk, via various transportation modes, to terminals where we deliver the propane to our retailer customers for subsequent delivery to their individual heating customers. We also create margin by selling propane for future physical delivery to third party users, such as retailers and industrial users. Through these transactions, we seek to maintain a position that is substantially balanced between propane purchases and sales and future delivery obligations. From time to time, we enter into various types of sale and exchange transactions including floating price collar arrangements, financial swaps and crude oil and LPG-related futures contracts as hedging devices. Except for pre-defined inventory positions, our policy is generally to purchase only LPG for which we have a market, and to structure our sales contracts so that LPG spot price fluctuations do not materially affect the segment profit we receive. Margin is created on the butane purchased by delivering large volumes during the short refinery blending season through the use of our extensive leased railcar fleet and the use of our own storage facilities and third party storage facilities. We also create margin on butane by capturing the difference in price between condensate and butane when butane is used to replace condensate as a diluent for the movement of Canadian heavy oil production. While we seek to maintain a position that is substantially balanced within our LPG activities, as a result of production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions, from time to time we experience net unbalanced positions for short periods of time. In connection with managing these positions and maintaining a constant presence in the marketplace, both necessary for our core business, our policies provide that any net imbalance may not exceed 250,000 barrels. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations.

LPG Exchanges. We pursue exchange opportunities to enhance margins throughout the marketing process. When opportunities arise to increase our margin or to acquire a volume of LPG that more closely matches our physical delivery requirement or the preferences of our customers, we exchange physical LPG with third parties. These exchanges are effected through contracts called exchange or buy-sell agreements. Through an exchange agreement, we agree to buy LPG that differs in terms of geographic location, type of LPG or physical delivery schedule from LPG we have available for sale. Generally, we enter into exchanges to acquire LPG at locations that are closer to our end markets in order to meet the delivery specifications of our physical delivery contracts.

Credit. Our merchant activities involve the purchase of crude oil and LPG for resale and require significant extensions of credit by our suppliers of crude oil and LPG. In order to assure our ability to perform our obligations under crude oil purchase agreements, various credit arrangements are negotiated with our suppliers. These arrangements include open lines of credit directly with us, and standby letters of credit issued under our senior unsecured revolving credit facility.

When we sell crude oil and LPG, we must determine the amount, if any, of the line of credit to be extended to any given customer. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures. If we determine that a customer should receive a credit line, we must then decide on the amount of credit that should be extended.

Because our typical crude oil sales transactions can involve tens of thousands of barrels of crude oil, the risk of nonpayment and nonperformance by customers is a major consideration in our business. We believe our sales are made to creditworthy entities or entities with adequate credit support. Generally, sales of crude oil are settled within 30 days of the month of delivery (in the case of foreign cargoes, typically 10 days after delivery), and pipeline, transportation and terminalling services also settle within 30 days from invoice for the provision of services.

We also have credit risk with respect to our sales of LPG; however, because our sales are typically in relatively small amounts to individual customers, we do not believe that we have material concentration of credit risk. Typically, we enter into annual contracts to sell LPG on a forward basis, as well as sell LPG on a current basis to local distributors and retailers. In certain cases our customers prepay for their purchases, in amounts ranging from approximately $2 per barrel to 100% of their contracted amounts. Generally, sales of LPG are settled within 30 days of the date of invoice.

Terminalling and Storage Operations

We own approximately 37 million barrels of terminalling and storage assets. Approximately 14 million barrels of capacity are used in our GMT&S segment, and the remaining 23 million barrels are used in our Pipeline segment. Our storage and terminalling operations increase our margins in our business of purchasing and selling crude oil and also generate revenue through a combination of storage and throughput charges to third parties. Storage fees are generated when we lease tank capacity to third parties. Terminalling fees, also referred to as throughput fees, are generated when we receive crude oil from one connecting pipeline and redeliver crude oil to another connecting carrier in volumes that allow the refinery to receive its crude oil on a ratable basis throughout a delivery period. Both terminalling and storage fees are generally earned from:

- refiners and gatherers that segregate or custom blend crudes for refining feedstocks; and

- pipeline operators, refiners or traders that need segregated tankage for foreign cargoes.

The tankage that is used to support our arbitrage activities positions us to capture margins in a contango market (when the oil prices for future deliveries are higher than the current prices) or when the market switches from contango to backwardation (when the oil prices for future deliveries are lower than the current prices).

Our most significant terminalling and storage asset is our Cushing Terminal located at the Cushing Interchange. The Cushing Interchange is one of the largest wet-barrel trading hubs in the U.S. and the delivery point for crude oil futures contracts traded on the NYMEX. The Cushing Terminal has been designated by the NYMEX as an approved delivery location for crude oil delivered under the NYMEX light sweet crude oil futures contract. As the NYMEX delivery point and a cash market hub, the Cushing Interchange serves as a primary source of refinery feedstock for the Midwest refiners and plays an integral role in establishing and maintaining markets for many varieties of foreign and domestic crude oil. Our Cushing Terminal was constructed in 1993, with an initial tankage capacity of 2 million barrels, to capitalize on the crude oil supply and demand imbalance in the Midwest. The Cushing Terminal is also used to support and enhance the margins associated with our merchant activities relating to our lease gathering and bulk purchasing activities. See " Gathering and Marketing Operations Bulk Purchases." Since 1999, we have completed four separate expansion phases, which increased the capacity of the Cushing Terminal to a total of approximately 6.3 million barrels. The Cushing Terminal now consists of fourteen 100,000-barrel tanks, four 150,000-barrel tanks and sixteen 270,000-barrel tanks, all of which are used to store and terminal crude oil. In January 2005, we announced the commencement of our Phase V expansion that will add approximately 1.1 million barrels of storage capacity to our Cushing Terminal. The Cushing Terminal also includes a pipeline manifold and pumping system that has an estimated throughput capacity of approximately 800,000 barrels per day. The Cushing Terminal is connected to the major pipelines and other terminals in the Cushing Interchange through pipelines that range in size from 10 inches to 24 inches in diameter.

The Cushing Terminal is designed to serve the needs of refiners in the Midwest. In order to service an increase in volumes and varieties of foreign and domestic crude oil projected to be transported through the Cushing Interchange, we incorporated certain attributes into the original design of the Cushing Terminal including:

- multiple, smaller tanks to facilitate simultaneous handling of multiple crude varieties in accordance with normal pipeline batch sizes;

- dual header systems connecting most tanks to the main manifold system to facilitate efficient switching between crude grades with minimal contamination;

- bottom drawn sumps that enable each tank to be efficiently drained down to minimal remaining volumes to minimize crude oil contamination and maintain crude oil integrity during changes of service;

- mixer(s) on each tank to facilitate blending crude oil grades to refinery specifications; and

- a manifold and pump system that allows for receipts and deliveries with connecting carriers at their maximum operating capacity.

As a result of incorporating these attributes into the design of the Cushing Terminal, we believe we are favorably positioned to serve the needs of Midwest refiners to handle an increase in the number of varieties of crude oil transported through the Cushing Interchange. The pipeline manifold and pumping system of our Cushing Terminal is designed to support more than 10 million barrels of tank capacity. Our tankage in Cushing ranges in age from less than a year old to approximately 11 years old and the average age is approximately 5 years old. In contrast, we estimate that of the approximately 21 million barrels of remaining tanks in Cushing owned by third parties, the average age is approximately 50 years and of that, approximately 9 million barrels has an average age of over 70 years. We believe that provides us with a competitive advantage over our competitors.

Our Cushing Terminal also incorporates numerous environmental and operational safeguards. We believe that our terminal is the only one at the Cushing Interchange in which each tank has a secondary liner (the equivalent of double bottoms), leak detection devices and secondary seals. The Cushing Terminal is the only terminal at the Cushing Interchange equipped with aboveground pipelines. The Cushing Terminal is operated by a computer system designed to monitor real-time operational data and each tank is cathodically protected. In addition, each tank is equipped with a high-level alarm system to prevent overflows; a double seal floating roof designed to minimize air emissions and prevent the possible accumulation of potentially flammable gases between fluid levels and the roof of the tank; and a foam dispersal system that, in the event of a fire, is fed by a fully automated fire water distribution network.

We also own LPG storage facilities located in Alto, Michigan, Schaefferstown, Pennsylvania and Claremont, New Hampshire. The Alto facility is approximately 20 miles southeast of Grand Rapids. The Alto facility was acquired from Ohio-Northwest Development Inc. in 2003 and is capable of storing over 1.2 million barrels of LPG. The Schaefferstown facility is approximately 65 miles northwest of Philadelphia and is capable of storing over 0.5 million barrels of propane. The Claremont facility is on the Vermont border and has the capacity to store approximately 17,000 barrels of propane. In addition, the Claremont facility has two truck loading stations and two rail unloading stations. We believe these facilities will further support the expansion of our LPG business in Canada and the northern tier of the U.S. as we combine the facilities' existing fee-based storage business with our wholesale propane marketing expertise. In addition, there may be opportunities to expand these facilities as LPG markets continue to develop in the region.

Crude Oil Volatility; Counter Cyclical Balance; Risk Management

Crude oil prices have historically been very volatile and cyclical, with NYMEX benchmark prices ranging from a high of over $58 per barrel in April 2005 to as low as $10 per barrel over the last 20 years. Segment profit from terminalling and storage activities is dependent on the crude oil throughput volume, capacity leased to third parties, capacity that we use for our own activities, and the level of other fees generated at our terminalling and storage facilities. Segment profit from our gathering and marketing activities is dependent on our ability to sell crude oil at a price in excess of our aggregate cost. Although margins may be affected during transitional periods, these operations are not directly affected by the absolute level of crude oil prices, but are affected by overall levels of supply and demand for crude oil and relative fluctuations in market related indices.

During periods when supply exceeds the demand for crude oil, the market for crude oil is often in contango, meaning that the price of crude oil for future deliveries is higher than current prices. A contango market has a generally negative impact on marketing margins, but is favorable to the storage business, because storage owners at major trading locations (such as the Cushing Interchange) can simultaneously purchase production at current prices for storage and sell at higher prices for future delivery.

When there is a higher demand than supply of crude oil in the near term, the market is backwardated, meaning that the price of crude oil for future deliveries is lower than current prices. A backwardated market has a positive impact on marketing margins because crude oil gatherers can capture a premium for prompt deliveries. In this environment, there is little incentive to store crude oil as current prices are above future delivery prices.

The periods between a backwardated market and a contango market are referred to as transition periods. Depending on the overall duration of these transition periods, how we have allocated our assets to particular strategies and the time length of our crude oil purchase and sale contracts and storage lease agreements, these transition periods may have either an adverse or beneficial affect on our aggregate segment profit. A prolonged transition from a backwardated market to a contango market, or vice versa (essentially a market that is neither in pronounced backwardation nor contango), represents the most difficult environment for our gathering, marketing, terminalling and storage activities. When the market is in contango, we will use our tankage to improve our gathering margins by storing crude oil we have purchased for delivery in future months that are selling at a higher price. In a backwardated market, we use less storage capacity but increased marketing margins provide an offset to this reduced cash flow. We believe that the combination of our terminalling and storage activities and gathering and marketing activities provides a counter cyclical balance that has a stabilizing effect on our operations and cash flow. References to counter-cyclical balance elsewhere in this report are referring to this relationship between our terminalling and storage activities and our gathering and marketing activities in transitioning crude oil markets.

As use of the financial markets for crude oil has increased by producers, refiners, utilities and trading entities, risk management strategies, including those involving price hedges using NYMEX futures contracts and derivatives, have become increasingly important in creating and maintaining margins. Such hedging techniques require significant resources dedicated to managing these positions. Our risk management policies and procedures are designed to monitor both NYMEX and over-the-counter positions and physical volumes, grades, locations and delivery schedules to ensure that our hedging activities are implemented in accordance with such policies. We have a risk management function that has direct responsibility and authority for our risk policies, our trading controls and procedures and certain other aspects of corporate risk management.

Our policy is to purchase only crude oil for which we have a market, and to structure our sales contracts so that crude oil price fluctuations do not materially affect the segment profit we receive. Except for the controlled trading program discussed below, we do not acquire and hold crude oil futures contracts or other derivative products for the purpose of speculating on crude oil price changes that might expose us to indeterminable losses.

While we seek to maintain a position that is substantially balanced within our crude oil lease purchase and LPG activities, we may experience net unbalanced positions for short periods of time as a result of production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions. In connection with managing these positions and maintaining a constant presence in the marketplace, both necessary for our core business, we engage in a controlled trading program for up to an aggregate of 500,000 barrels of crude oil. This controlled trading activity is monitored independently by our risk management function and must take place within predefined limits and authorizations.

In order to hedge margins involving our physical assets and manage risks associated with our crude oil purchase and sale obligations, we use derivative instruments, including regulated futures and options transactions, as well as over-the-counter instruments. In analyzing our risk management activities, we draw a distinction between enterprise level risks and trading related risks. Enterprise level risks are those that underlie our core businesses and may be managed based on whether there is value in doing so. Conversely, trading related risks (the risks involved in trading in the hopes of generating an increased return) are not inherent in the core business; rather, those risks arise as a result of engaging in the trading activity. We have a Risk Management Committee that approves all new risk management strategies through a formal process. With the exception of the controlled trading program, our approved strategies are intended to mitigate enterprise level risks that are inherent in our core businesses of crude oil gathering and marketing and storage.

Although the intent of our risk-management strategies is to hedge our margin, not all of our derivatives qualify for hedge accounting. In such instances, changes in the fair values of these derivatives will receive mark-to-market treatment in current earnings, and result in greater potential for earnings volatility.

Customers

Marathon Ashland Petroleum ("MAP") accounted for 10%, 12% and 10% of our revenues for each of the three years in the period ended December 31, 2004. BP Oil Supply Company also accounted for 10% of our revenues for the year ended December 31, 2004. No other customers accounted for 10% or more of our revenues during the three years ended December 31, 2004. The majority of the revenues from Marathon Ashland Petroleum and BP Oil Supply Company pertain to our gathering, marketing, terminalling and storage operations. We believe that the loss of these customers would have only a short-term impact on our operating results. There can be no assurance, however, that we would be able to identify and access a replacement market at comparable margins.

Competition

Competition among pipelines is based primarily on transportation charges, access to producing areas and demand for the crude oil by end users. We believe that high capital requirements, environmental considerations and the difficulty in acquiring rights-of-way and related permits make it unlikely that competing pipeline systems comparable in size and scope to our pipeline systems will be built in the foreseeable future. However, to the extent there are already third-party owned pipelines or owners with joint venture pipelines with excess capacity in the vicinity of our operations, we will be exposed to significant competition based on the incremental cost of moving an incremental barrel of crude oil.

We face intense competition in our gathering, marketing, terminalling and storage operations. Our competitors include other crude oil pipeline companies, the major integrated oil companies, their marketing affiliates and independent gatherers, brokers and marketers of widely varying sizes, financial resources and experience. Some of these competitors have capital resources many times greater than ours, and control greater supplies of crude oil.

Regulation

Our operations are subject to extensive regulations. We estimate that we are subject to regulatory oversight by over 70 federal, state, provincial and local departments and agencies, many of which are authorized by statute to issue and have issued laws and regulations binding on the oil pipeline industry, related businesses and individual participants. The failure to comply with such rules and regulations can result in substantial penalties. The regulatory burden on our operations increases our cost of doing business and, consequently, affects our profitability. However, except for certain exemptions that apply to smaller companies, we do not believe that we are affected in a significantly different manner by these laws and regulations than are our competitors. Following is a discussion of certain laws and regulations affecting us. However, due to the myriad of complex federal, state, provincial and local regulations that may affect us, directly or indirectly, you should not rely on such discussion as an exhaustive review of all regulatory considerations affecting our operations.

Pipeline and Storage Regulation

A substantial portion of our petroleum pipelines and storage tanks in the United States are subject to regulation by the U.S. Department of Transportation ("DOT") with respect to the design, installation, testing, construction, operation, replacement and management of pipeline and tank facilities. In addition, we must permit access to and copying of records, and must make certain reports available and provide information as required by the Secretary of Transportation. Federal pipeline safety rules also require pipeline operators to develop and maintain a written qualification program for individuals performing covered tasks on pipeline facilities. Comparable regulation exists in some states in which we conduct intrastate common carrier or private pipeline operations, as well as in Canada under the National Energy Board ("NEB") and provincial agencies.

Since 2000, the DOT has adopted a series of rules requiring operators of interstate pipelines transporting hazardous liquids or natural gas to develop and follow an integrity management program that provides for continual assessment of the integrity of all pipeline segments that could affect so-called "high consequence areas," including high population areas, areas that are sources of drinking water, ecological resource areas that are unusually sensitive to environmental damage from a pipeline release, and commercially navigable waterways. Segments of our pipelines transporting hazardous liquids in high consequence areas are subject to these DOT rules and therefore obligate us to evaluate pipeline conditions by means of periodic internal inspection, pressure testing, or other equally effective assessment means, and to correct identified anomalies. If, as a result of our evaluation process, we determine that there is a need to provide further protection to high consequence areas, then we will be required to implement additional spill prevention, mitigation and risk control measures for our pipelines. The DOT rules also require us to evaluate and, as necessary, improve our management and analysis processes for integrating available integrity related data relating to our pipeline segments and to remediate potential problems found as a result of the required assessment and evaluation process. Costs associated with this program were approximately $1.0 million in 2003 and approximately $5 million in 2004. Based on currently available information, our preliminary estimate for 2005 is approximately $8 million. The relative increase in program cost over the last few years is primarily attributable to pipeline segments acquired in 2003 and 2004 (including the Link assets), which are subject to the new rules and for which assessment commenced in 2004. Certain of these costs are recurring in nature and thus will impact future periods. We will continue to refine our estimates as information from our assessments is collected. Our estimates do not include the potential costs associated with assets acquired in the future. Although we believe that our pipeline operations are in substantial compliance with currently applicable regulatory requirements, we cannot predict the potential costs associated with additional, future regulation.

The DOT is currently considering expanding the scope of its pipeline regulation to include certain gathering pipeline systems that are not currently subject to regulation. This expanded scope would likely include the establishment of additional pipeline integrity management programs for these newly regulated pipelines. The DOT is in the initial stages of evaluating this initiative and we do not currently know what, if any, impact this will have on our operating expenses. However, we cannot assure you that future costs related to the potential programs will not be material. However, even if the DOT does not expand the scope of its pipeline regulation to include pipeline systems not currently regulated, we may still need to upgrade or expand our existing pipeline integrity management programs to remain in compliance with the Federal Water Pollution Control Act and other environmental laws. We could be required to spend substantial sums to ensure the integrity of and upgrade our pipeline systems to maintain environmental compliance, and in some cases, we may take pipelines out of service if we believe the cost of upgrades will exceed the value of the pipelines. We cannot provide any assurance as to the ultimate amount or timing of future pipeline integrity expenditures for environmental compliance.

States are largely preempted by federal law from regulating pipeline safety but may assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. In practice, states vary considerably in their authority and capacity to address pipeline safety. We do not anticipate any significant problems in complying with applicable state laws and regulations in those states in which we operate.

The DOT has adopted API 653 as the standard for the inspection, repair, alteration and reconstruction of existing crude oil storage tanks subject to DOT jurisdiction (approximately 83% of our 37 million barrels are subject to DOT jurisdiction). API 653 requires regularly scheduled inspection and repair of tanks remaining in service. Full compliance is required by 2009. Costs associated with this program were approximately $3 million in 2004. Based on currently available information, we anticipate we will spend an approximate average of $6 million per year from 2005 through 2009 in connection with API 653 compliance activities. Such amounts incorporate the costs associated with the assets acquired in 2003 and 2004. Our estimates do not include the potential costs associated with assets acquired in the future. We will continue to refine our estimates as information from our assessments is collected.

We have instituted security measures and procedures, in accordance with DOT guidelines, to enhance the protection of certain of our facilities from terrorist attack. We cannot assure you that these security measures would fully protect our facilities from a concentrated attack. See " Operational Hazards and Insurance."

In Canada, the NEB and provincial agencies such as the Alberta Energy and Utilities Board and the Saskatchewan Industry and Resources have promulgated regulations similar to the domestic pipeline integrity management rules and API 653 standards. We spent approximately $4.1 million in 2004 in compliance activities. Our preliminary estimate for 2005 is approximately $5.1 million. In addition, we expect to incur compliance costs under other regulations related to pipeline and storage tank integrity, such as operator competency programs, regulatory upgrades to our operating and maintenance systems and environmental upgrades of buried sump tanks. Our preliminary estimate for such costs for 2005 is approximately $0.5 million. Certain of these costs are recurring in nature and thus will impact future periods. We will continue to refine our estimates as information from our assessments is collected. Our estimates do not include the potential costs associated with assets acquired in the future. Although we believe that our pipeline operations are in substantial compliance with currently applicable regulatory requirements, we cannot predict the potential costs associated with additional, future regulation.

Asset acquisitions are an integral part of our business strategy. As we acquire additional assets, we may be required to incur additional costs in order to ensure that the acquired assets comply with the regulatory standards in the U.S. and Canada.

Transportation Regulation

General Interstate Regulation. Our interstate common carrier pipeline operations are subject to rate regulation by the FERC under the Interstate Commerce Act. The Interstate Commerce Act requires that tariff rates for petroleum pipelines, which includes both crude oil pipelines and refined product pipelines, be just and reasonable and non-discriminatory.

State Regulation. Our intrastate pipeline transportation activities are subject to various state laws and regulations, as well as orders of state regulatory bodies.

Canadian Regulation. Our Canadian pipeline assets are subject to regulation by the NEB and by provincial agencies. With respect to a pipeline over which it has jurisdiction, each of these agencies has the power, upon application by a third party, to determine the rates we are allowed to charge for transportation on, and set other terms of access to, such pipeline. In such circumstances, if the relevant regulatory agency determines that the applicable terms and conditions of service are not just and reasonable, the agency can amend the offending provisions of an existing transportation contract.

Energy Policy Act of 1992 and Subsequent Developments. In October 1992, Congress passed the Energy Policy Act of 1992 ("EPAct"), which among other things, required the FERC to issue rules establishing a simplified and generally applicable ratemaking methodology for petroleum pipelines and to streamline procedures in petroleum pipeline proceedings. The FERC responded to this mandate by issuing several orders, including Order No. 561. Beginning January 1, 1995, Order No. 561 enables petroleum pipelines to change their rates within prescribed ceiling levels that are tied to an inflation index. Rate increases made pursuant to the indexing methodology are subject to protest, but such protests must show that the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs. If the indexing methodology results in a reduced ceiling level that is lower than a pipeline's filed rate, Order No. 561 requires the pipeline to reduce its rate to comply with the lower ceiling unless doing so would reduce a rate "grandfathered" by EPAct (see below) below the grandfathered level. A pipeline must, as a general rule, utilize the indexing methodology to change its rates. The FERC, however, retained cost-of-service ratemaking, market based rates, and settlement as alternatives to the indexing approach, which alternatives may be used in certain specified circumstances. The EPAct deemed petroleum pipeline rates in effect for the 365-day period ending on the date of enactment of EPAct that had not been subject to complaint, protest or investigation during that 365-day period to be just and reasonable under the Interstate Commerce Act. Generally, complaints against such "grandfathered" rates may only be pursued if the complainant can show that a substantial change has occurred since the enactment of EPAct in either the economic circumstances of the oil pipeline, or in the nature of the services provided, that were a basis for the rate. EPAct places no such limit on challenges to a provision of an oil pipeline tariff as unduly discriminatory or preferential.

On July 20, 2004, the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") issued its opinion in *BP West Coast Products, LLC v. FERC*, which upheld FERC's determination that the rates of an interstate petroleum products pipeline, SFPP, L.P. ("SFPP"), were grandfathered rates under EPAct and that SFPP's shippers had not demonstrated substantially changed circumstances that would justify modification of those rates. The court also vacated the portion of the FERC's decision applying the *Lakehead* policy, under which the FERC allowed a regulated entity organized as a master limited partnership to include in its cost-of-service an income tax allowance to the extent that entity's unitholders were corporations subject to income tax. On December 2, 2004, the FERC issued a Notice of Inquiry that called for comments regarding whether *BP West Coast* applies broadly or only to the specific facts of that case. In response to the comments received, on May 4, 2005, the FERC adopted a policy statement providing that all entities owning public utility assets oil and gas pipelines and electric utilities would be permitted to include an income tax allowance in their cost-of-service rates to reflect the actual or potential income tax liability attributable to their public utility income, regardless of the form of ownership. Any tax pass-through entity seeking an income tax allowance would have to establish that its partners or members have an actual or potential income tax obligation on the entity's public utility income. The FERC expressed the intent to implement its policy in individual cases as they arise. Subject to that case-specific implementation, the policy appears to provide an opportunity for partnership-owned pipelines to seek allowances based upon their entire income paid to partners, rather than the partial allowance provided under the prior *Lakehead* policy.

Evaluation of the impact of this policy statement will have to await further developments in various pending cases.

Additionally, in *BP West Coast*, the court remanded to the FERC the issue of whether SFPP's revised cost-of-service without a tax allowance would qualify as a substantially changed circumstance that would justify modification of SFPP's rates. Because the court remanded to the FERC and because the FERC's ruling on the substantially changed circumstances issue will focus on the facts and record presented to it, it is not clear what impact, if any, the opinion will have on our rates or on the rates of other FERC-jurisdictional pipelines organized as tax pass-through entities. Moreover, it is not clear to what extent FERC's actions taken in response to *BP West Coast* will be challenged and, if so, whether they will withstand further FERC or judicial review.

In a subsequent FERC proceeding involving SFPP, certain shippers again challenged SFPP's grandfathered rates on the basis of substantially changed circumstances since the passage of EPAct. On March 26, 2004, the FERC issued an order in that case, finding that some of SFPP's rates were not grandfathered and that there were substantially changed circumstances on certain of their systems. Several of the participants in the proceeding have requested rehearing of the FERC's order, and several participants have filed petitions with the D.C. Circuit for review of the order. FERC and court action on those petitions is pending. We are uncertain whether FERC's order will remain intact and, if it does, what effect, if any, that order might have on our grandfathered rates should they be challenged.

Our Pipelines. The FERC generally has not investigated rates on its own initiative when those rates have not been the subject of a protest or complaint by a shipper. Substantially all of our segment profit on transportation is produced by rates that are either grandfathered or set by agreement with one or more shippers.

Trucking Regulation

We operate a fleet of trucks to transport crude oil and oilfield materials as a private, contract and common carrier. We are licensed to perform both intrastate and interstate motor carrier services. As a motor carrier, we are subject to certain safety regulations issued by the Department of Transportation. The trucking regulations cover, among other things, driver operations, maintaining log books, truck manifest preparations, the placement of safety placards on the trucks and trailer vehicles, drug and alcohol testing, safety of operation and equipment, and many other aspects of truck operations. We are also subject to the Occupational Safety and Health Act, as amended ("OSHA"), with respect to our trucking operations.

Our trucking assets in Canada are subject to regulation by both federal and provincial transportation agencies in the provinces in which they are operated. These regulatory agencies do not set freight rates, but do establish and administer rules and regulations relating to other matters including equipment and driver licensing, equipment inspection, hazardous materials and safety.

Cross Border Regulation

As a result of our Canadian acquisitions and cross border activities, we are subject to regulatory matters including export licenses, tariffs, Canadian and U.S. customs and tax issues and toxic substance certifications. Regulations include the Short Supply Controls of the Export Administration Act, the North American Free Trade Agreement and the Toxic Substances Control Act. Violations of these license, tariff and tax reporting requirements could result in the imposition of significant administrative, civil and criminal penalties. Furthermore, the failure to comply with U.S., Canadian, state, provincial and local tax requirements could lead to the imposition of additional taxes, interest and penalties.

Environmental, Health and Safety Regulation

General

Our operations involving the storage, treatment, processing, and transportation of liquid hydrocarbons including crude oil are subject to stringent federal, state, provincial and local laws and regulations governing the discharge of materials into the environment or otherwise relating to protection of the environment. As with the industry generally, compliance with these laws and regulations increases our overall cost of business, including our capital costs to construct, maintain and upgrade equipment and facilities. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial liabilities, and even the issuance of injunctions that may restrict or prohibit our operations. Environmental laws and regulations are subject to change, and we cannot provide any assurance that compliance with current and future laws and regulations will not have a material affect on our results of operations or earnings. A discharge of hazardous liquids into the environment could, to the extent such event is not insured, subject us to substantial expense, including both the cost to comply with applicable laws and regulations and any claims made by neighboring landowners and other third parties for personal injury and property damage.

Water

The U.S. Oil Pollution Act ("OPA") and analogous state and Canadian federal and provincial laws subject owners of facilities to strict, joint and potentially unlimited liability for containment and removal costs, natural resource damages, and certain other consequences of an oil spill, where such spill is into navigable waters, along shorelines or in the exclusive economic zone of the U.S. The OPA establishes a liability limit of $350 million for onshore facilities. However, a party cannot take advantage of this liability limit if the spill is caused by gross negligence or willful misconduct, resulted from a violation of a federal safety, construction, or operating regulation, or if there is a failure to report a spill or cooperate in the cleanup. We believe that we are in substantial compliance with applicable OPA requirements.

The U.S. Clean Water Act and analogous state and Canadian federal and provincial laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters of the United States and Canada, as well as state and provincial waters. Permits must be obtained to discharge pollutants into these waters. The Clean Water Act imposes substantial potential liability for the removal and remediation of pollutants. Although we can give no assurances, we believe that compliance with existing permits and compliance with foreseeable new permit requirements will not have a material adverse effect on our financial condition or results of operations.

Some states and all provinces maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. We believe that we are in substantial compliance with any such applicable state requirements.

In addition to the costs described above we could also be required to spend substantial sums to ensure the integrity of and upgrade our pipeline systems as a result of oil spills, and in some cases, we may take pipelines out of service if we believe the cost of upgrades will exceed the value of the pipelines. We cannot provide any assurance as to the ultimate amount or timing of future pipeline integrity expenditures for environmental compliance.

Air Emissions

Our operations are subject to the U.S. Clean Air Act and comparable state and provincial laws. Under these laws, permits may be required before construction can commence on a new source of potentially significant air emissions and operating permits may be required for sources already constructed. We may be required to incur certain capital expenditures in the next several years for air pollution control equipment in connection with obtaining or maintaining permits and approvals for sources of air emissions. While we believe that our operations are in substantial compliance with these laws in those areas in which we operate, we can provide no assurance that future compliance obligations will not have a material adverse effect on our financial condition or results of operations.

Canada is a participant in the Kyoto Protocol of the United Nations Framework Convention on Climate Change. The Kyoto Protocol requires participating developed nations such as Canada to reduce their emissions of carbon dioxide and other "greenhouse gases" to five percent below 1990 levels by 2012. As a result, already stringent air emissions regulations applicable to our operations in Canada will be replaced, by 2010, with even stricter requirements. We are currently monitoring the impact on our operations of proposed changes in regulations that will be necessary as a result of Canada's participation in the Protocol.

Solid Waste

We generate wastes, including hazardous wastes, that are subject to the requirements of the federal Resource Conservation and Recovery Act ("RCRA") and comparable state and provincial laws. We are not required to comply with a substantial portion of the RCRA requirements because our operations generate primarily oil and gas wastes, which currently are excluded from consideration as RCRA hazardous wastes. However, it is possible that in the future the exclusion of oil and gas wastes from regulation as RCRA hazardous wastes may be eliminated, in which event, our wastes as well as the wastes of our competitors in the oil and gas industry will be subject to more rigorous and costly disposal requirements, resulting in additional capital expenditures or operating expenses for us and the industry in general.

Hazardous Substances

The federal Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), also known as "Superfund," and comparable state and provincial laws impose liability, without regard to fault or the legality of the original act, on certain classes of persons that contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the site or sites where the release occurred and companies that disposed of, or arranged for the disposal of, the hazardous substances found at the site. Under CERCLA, such persons may be subject to strict joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. In the course of our ordinary operations, we may generate waste that falls within CERCLA's definition of a "hazardous substance," in which event we may be held jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which such hazardous substances have been released into the environment.

OSHA

We are subject to the requirements of OSHA, and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that certain information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with OSHA requirements, including general industry standards, record keeping requirements and monitoring of occupational exposure to regulated substances. OSHA has also been given jurisdiction over enforcement of legislation designed to protect employees who provide evidence in fraud cases from retaliation by their employer.

Similar regulatory requirements exist in Canada under the federal and provincial Occupational Health and Safety Acts and related regulations. The agencies with jurisdiction under these regulations are empowered to enforce them through inspection, audit, incident investigation or public or employee complaint. Additionally, recent legislation directly ties corporate accountability to the Criminal Code of Canada. This legislation enables occupational health and safety ("OH&S") regulators to prosecute organizations and individuals criminally for violations of the regulations. We believe that our operations are in substantial compliance with applicable OH&S requirements.

Endangered Species Act

The federal Endangered Species Act ("ESA") restricts activities that may affect endangered species or their habitats. Although certain of our facilities are in areas that may be designated as habitat for endangered species, we believe that we are in substantial compliance with the ESA. However, the discovery of previously unidentified endangered species could cause us to incur additional costs or operation restrictions or bans in the affected area, which costs, restrictions, or bans could have a material adverse effect on our financial condition or results of operations. Similar regulation (the Species Risk Act) applies to our Canadian operations.

Hazardous Materials Transportation Requirements

The DOT regulations affecting pipeline safety require pipeline operators to implement measures designed to reduce the environmental impact of oil discharge from onshore oil pipelines. These regulations require operators to maintain comprehensive spill response plans, including extensive spill response training for pipeline personnel. In addition, DOT regulations contain detailed specifications for pipeline operation and maintenance. We believe our operations are in substantial compliance with such regulations. See " Regulation Pipeline and Storage Regulation."

Environmental Remediation

We currently own or lease properties where hazardous liquids, including hydrocarbons, are being or have been handled. These properties and the hazardous liquids or associated generated wastes disposed thereon may be subject to CERCLA, RCRA and analogous state and Canadian federal and provincial laws. Under such laws, we could be required to remove or remediate hazardous liquids or associated generated wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial operations to prevent future contamination.

We maintain insurance of various types with varying levels of coverage that we consider adequate under the circumstances to cover our operations and properties. The insurance policies are subject to deductibles and retention levels that we consider reasonable and not excessive. Consistent with insurance coverage generally available in the industry, in certain circumstances our insurance policies provide limited coverage for losses or liabilities relating to gradual pollution, with broader coverage for sudden and accidental occurrences.

In addition, we have entered into indemnification agreements with various counterparties in conjunction with several of our acquisitions. Allocation of environmental liability is an issue negotiated in connection with each of our acquisition transactions. In each case, we make an assessment of potential environmental exposure based on available information. Based on that assessment and relevant economic and risk factors, we determine whether to negotiate an indemnity, what the terms of any indemnity should be (for example, minimum thresholds or caps on exposure) and whether to obtain insurance, if available. In some cases, we have received contractual protections in the form of environmental indemnifications from several predecessor operators for properties acquired by us that are contaminated as a result of historical operations. These contractual indemnifications typically are subject to specific monetary requirements that must be satisfied before indemnification will apply and have term and total dollar limits.

The acquisitions we completed in 2003 and 2004 include a variety of provisions dealing with the allocation of responsibility for environmental costs that range from no or limited indemnities from the sellers to indemnification from sellers with defined limitations on their maximum exposure. We have not obtained insurance for any of the conditions related to our 2003 acquisitions, and only in limited circumstances for our 2004 acquisitions.

For instance, in connection with the Link acquisition, we identified a number of environmental liabilities, for which we received a purchase price reduction from Link. A substantial portion of these environmental liabilities are associated with the former Texas New Mexico ("TNM") pipeline assets. On the effective date of the acquisition, we and TNM entered into a cost-sharing agreement whereby, on a tiered basis, we will bear $11 million of the first $20 million of pre-May 1999 environmental issues. We will also bear the first $25,000 per site for new sites which were not identified at the time we entered into the agreement (capped at 100 sites). TNM will pay all costs in excess of $20 million (excluding the deductible for new sites). TNM's obligations are guaranteed by Shell Oil Products ("SOP"). We recorded a reserve for environmental liabilities of approximately $17.0 million in connection with the Link acquisition.

In connection with the acquisition of certain crude oil transmission and gathering assets from SOP in 2002, Shell purchased an environmental insurance policy covering known and unknown environmental matters associated with operations prior to closing. We are a named beneficiary under the policy, which has a $100,000 deductible per site, an aggregate coverage limit of $70 million, and expires in 2012. Shell has recently made a claim against the policy; however, we do not believe that the claim will substantially reduce our coverage under the policy.

In connection with our 1999 acquisition of Scurlock Permian LLC from MAP, we were indemnified by MAP for any environmental liabilities attributable to Scurlock's business or properties which occurred prior to the date of the closing of the acquisition. This indemnity applied to claims that exceeded $25,000 individually and $1.0 million in the aggregate. For the indemnity to apply, we were required to assert any claims on or before May 15, 2003. In conjunction with the expiration of this indemnity, we reached agreement with respect to MAP's remaining indemnity obligations. Under the terms of this agreement, MAP will continue to remain obligated for liabilities associated with two Superfund sites at which it is alleged that Scurlock Permian deposited waste oils. In addition, MAP paid us $4.6 million cash as satisfaction of its obligations with respect to other sites. During 2002, we had reassessed previous investigations and completed environmental studies related to environmental conditions associated with our 1999 acquisitions. As a result of that reassessment, we established an additional reserve of $1.2 million.

Other assets we have acquired or will acquire in the future may have environmental remediation liabilities for which we are not indemnified. We have in the past experienced and in the future will likely experience releases of crude oil into the environment from our pipeline and storage operations, or discover releases that were previously unidentified. Although we maintain a program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to environmental releases from our assets may substantially affect our business.

At March 31, 2005, our reserve for environmental liabilities totaled approximately $23.3 million (approximately $16.3 million of this reserve is related to liabilities assumed as part of the Link acquisition). Approximately $12.1 million of our environmental reserve is classified as current and $11.2 million is classified as long-term. At December 31, 2004, we have recorded receivables totaling approximately $6.5 million for amounts recoverable under insurance and from third parties under indemnification agreements.

In some cases, the actual cash expenditures may not occur for three to five years. We believe that this reserve is adequate, and in conjunction with our indemnification arrangements, should prevent remediation costs from having a material adverse effect on our financial condition, results of operations, or cash flows. Our estimates used in these reserves are based on all known facts at the time and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment and the possibility of existing legal claims giving rise to additional claims. Therefore, no assurances can be made that any costs incurred in excess of this reserve or outside of the indemnifications would not have a material adverse effect on our financial condition, results of operations, or cash flows.

Operational Hazards and Insurance

Pipelines, terminals, trucks or other facilities or equipment may experience damage as a result of an accident or natural disaster. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. Since we and our predecessors commenced midstream crude oil activities in the early 1990s, we have maintained insurance of various types and varying levels of coverage that we consider adequate under the circumstances to cover our operations and properties. The insurance policies are subject to deductibles and retention levels that we consider reasonable and not excessive. However, such insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues. Consistent with insurance coverage generally available to the industry, in certain circumstances our insurance policies provide limited coverage for losses or liabilities relating to gradual pollution, with broader coverage for sudden and accidental occurrences. Over the last several years, our operations have expanded significantly, with total assets increasing over 400% since the end of 1998. At the same time that the scale and scope of our business activities have expanded, the breadth and depth of the available insurance markets have contracted. Notwithstanding what we believe is a favorable claims history, the overall cost of such insurance as well as the deductibles and overall retention levels that we maintain have increased. As a result, we have elected to self insure more activities against certain of these operating hazards and expect this trend will continue in the future. Certain aspects of these conditions were exacerbated by the events of September 11, 2001, and their overall effect on the insurance industry have adversely impacted the availability and cost of certain coverages. Due to these events, insurers have excluded acts of terrorism and sabotage from our insurance policies and on certain of our key assets, we have elected to purchase a separate insurance policy for acts of terrorism and sabotage.

Since the terrorist attacks, the United States Government has issued numerous warnings that energy assets, including our nation's pipeline infrastructure, may be future targets of terrorist organizations. These developments expose our operations and assets to increased risks. We have instituted security measures and procedures in conformity with DOT guidance. We will institute, as appropriate, additional security measures or procedures indicated by the DOT or the Transportation Safety Administration. However, we cannot assure you that these or any other security measures would protect our facilities from a concentrated attack. Any future terrorist attacks on our facilities, those of our customers and, in some cases, those of our competitors, could have a material adverse effect on our business, whether insured or not.

The occurrence of a significant event not fully insured, indemnified or reserved against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe we are adequately insured for public liability and property damage to others with respect to our operations. We believe that our levels of coverage and retention are generally consistent with those of similarly situated companies in our industry. With respect to all of our coverage, no assurance can be given that we will be able to maintain adequate insurance in the future at rates we consider reasonable, or that we have established adequate reserves to the extent that such risks are not insured.

Title to Properties and Rights-of-Way

We believe that we have satisfactory title to all of our assets. Although title to such properties are subject to encumbrances in certain cases, such as customary interests generally retained in connection with acquisition of real property, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens and minor easements, restrictions and other encumbrances to which the underlying properties were subject at the time of acquisition by our predecessor or us, we believe that none of these burdens will materially detract from the value of such properties or from our interest therein or will materially interfere with their use in the operation of our business.

Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of such property and, in some instances, such rights-of-way are revocable at the election of the grantor. In many instances, lands over which rights-of-way have been obtained are subject to prior liens that have not been subordinated to the right-of-way grants. In some cases, not all of the apparent record owners have joined in the right-of-way grants, but in substantially all such cases, signatures of the owners of majority interests have been obtained. We have obtained permits from public authorities to cross over or under, or to lay facilities in or along water courses, county roads, municipal streets and state highways, and in some instances, such permits are revocable at the election of the grantor. We have also obtained permits from railroad companies to cross over or under lands or rights-of-way, many of which are also revocable at the grantor's election. In some cases, property for pipeline purposes was purchased in fee. All of the pump stations are located on property owned in fee or property under leases. In certain states and under certain circumstances, we have the right of eminent domain to acquire rights-of-way and lands necessary for our common carrier pipelines.

Some of the leases, easements, rights-of-way, permits and licenses transferred to us, upon our formation in 1998 and in connection with acquisitions we have made since that time, required the consent of the grantor to transfer such rights, which in certain instances is a governmental entity. We believe that we have obtained such third party consents, permits and authorizations as are sufficient for the transfer to us of the assets necessary for us to operate our business in all material respects as described in this report. With respect to any consents, permits or authorizations that have not yet been obtained, we believe that such consents, permits or authorizations will be obtained within a reasonable period, or that the failure to obtain such consents, permits or authorizations will have no material adverse effect on the operation of our business.

Employees

To carry out our operations, our general partner or its affiliates employed approximately 1,950 employees at March 31, 2005. None of the employees of our general partner were represented by labor unions, and our general partner considers its employee relations to be good.

Litigation

Export License Matter. In our gathering and marketing activities, we import and export crude oil from and to Canada. Exports of crude oil are subject to the "short supply" controls of the Export Administration Regulations ("EAR") and must be licensed by the Bureau of Industry and Security (the "BIS") of the U.S. Commerce Department. In 2002, we determined that we may have violated the terms of our licenses with respect to the quantity of crude oil exported and the end-users in Canada. Export of crude oil except as authorized by license is a violation of the EAR. In October 2002, we submitted to the BIS an initial notification of voluntary disclosure. The BIS subsequently informed us that we could continue to export while previous exports were under review. We applied for and received several new licenses allowing for export volumes and end users that more accurately reflect our anticipated business and customer needs. We also conducted reviews of new and existing contracts and implemented new procedures and practices in order to monitor compliance with applicable laws regarding the export of crude oil to Canada. As a result, we subsequently submitted additional information to the BIS in October 2003 and May 2004. In August 2004, we received a request from the BIS for additional information. We have responded to this and subsequent requests, and continue to cooperate fully with BIS officials. At this time, we have received neither a warning letter nor a charging letter, which could involve the imposition of penalties, and no indication of what penalties the BIS might assess. As a result, we cannot reasonably estimate the ultimate impact of this matter.

Alfons Sperber v. Plains Resources Inc., et al. On December 18, 2003, a putative class action lawsuit was filed in the Delaware Chancery Court, New Castle County, entitled Alfons Sperber v. Plains Resources Inc., et al. This suit, brought on behalf of a putative class of Plains All American Pipeline, L.P. common unitholders, asserted breach of fiduciary duty and breach of contract claims against us, Plains AAP, L.P., and Plains All American GP LLC and its directors, as well as breach of fiduciary duty claims against Plains Resources Inc. and its directors. (Plains Resources, Inc. is a unitholder and an interest owner in our general partner. See "Security Ownership of Certain Beneficial Owners and Management and Related Unitholders' Matters.") The complaint sought to enjoin or rescind a proposed acquisition of all of the outstanding stock of Plains Resources Inc., as well as declaratory relief, an accounting, disgorgement and the imposition of a constructive trust, and an award of damages, fees, expenses and costs, among other things. This lawsuit has been settled in principle. The court has approved the settlement and the settlement became final in March 2005.

Pipeline Releases. In December 2004 and January 2005, we experienced two unrelated releases of crude oil that reached rivers located near the sites where the releases originated. In late December 2004, one of our pipelines in West Texas experienced a rupture that resulted in the release of approximately 4,500 barrels of crude oil, a portion of which reached a remote location of the Pecos River. In early January 2005, an overflow from a temporary storage tank located in East Texas resulted in the release of approximately 1,200 barrels of crude oil, a portion of which reached the Sabine River. In both cases, emergency response personnel under the supervision of a unified command structure consisting of representatives of Plains Pipeline, the U.S. Environmental Protection Agency, the Texas Commission on Environmental Quality and the Texas Railroad Commission conducted clean-up operations at each site. Approximately 4,200 barrels and 980 barrels were recovered from the two respective sites. The unrecovered oil has been or will be removed or otherwise addressed by us in the course of site remediation. Aggregate costs associated with the releases, including estimated remediation costs, are estimated to be approximately $3.0 million to $3.5 million. We continue to work with the appropriate state and federal environmental authorities in responding to the releases and no enforcement proceedings have been instituted by any governmental authority at this time.

Other. We, in the ordinary course of business, are a claimant and/or a defendant in various other legal proceedings. We do not believe that the outcome of these other legal proceedings, individually and in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows.

Unauthorized Trading Loss

In November 1999, we discovered that a former employee had engaged in unauthorized trading activity that resulted in significant losses and litigation and had a temporary, but material adverse impact on our liquidity and our relationship with our customers. A full investigation into the unauthorized trading activities by outside legal counsel and independent accountants and consultants determined that the vast majority of the losses occurred in 1999, but also extended into 1998 and required restatements of our financial statements for the applicable periods. Including litigation settlement costs, the aggregate losses associated with this event totaled approximately $181 million. All of the cases were settled and paid. Additionally, based on recommendations from experts involved in the investigation, we made significant enhancements to our systems, policies and procedures and developed and adopted a written policy document and manual of procedures designed to enhance our processes and procedures and improve our ability to detect any activity that might occur at an early stage. We can give no assurance that the above steps will serve to detect and prevent all violations of our trading policy; however, we believe that such steps substantially reduce the possibility of a recurrence of unauthorized trading activities, and that any material unauthorized trading that does occur would be detected at an early stage.

MANAGEMENT

Partnership Management and Governance

As is the case with many publicly traded partnerships, we do not directly have officers, directors or employees. Our operations and activities are managed by the general partner of our general partner, Plains All American GP LLC, which employs our management and operational personnel (other than our Canadian personnel who are employed by PMC (Nova Scotia) Company). References to our general partner, unless the context otherwise requires, include Plains All American GP LLC. References to our officers, directors and employees are references to the officers, directors and employees of Plains All American GP LLC (or, in the case of our Canadian and LPG operations, PMC (Nova Scotia) Company).

Our general partner manages our operations and activities. Unitholders are limited partners and do not directly or indirectly participate in our management or operation. Our general partner owes a fiduciary duty to the unitholders, as limited by our partnership agreement. As a general partner, our general partner is liable for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically non-recourse to it. Whenever possible, our general partner intends to incur indebtedness or other obligations on a non-recourse basis.

Our partnership agreement provides that the general partner will manage and operate us and that, unlike holders of common stock in a corporation, unitholders will have only limited voting rights on matters affecting our business or governance. Specifically, our partnership agreement defines "Board of Directors" to mean the board of directors of Plains All American GP LLC, which is comprised of up to eight directors elected by the members of Plains All American GP LLC, and not by the unitholders. The four owners that hold 9% or greater of the outstanding membership interests of Plains All American GP LLC have the right to designate one director each, one director is the Chairman and CEO and three independent directors are elected by majority vote of the membership owners of Plains All American GP LLC. Thus, the corporate governance of Plains All American GP LLC is, in effect, the corporate governance of our partnership, subject in all cases to any specific unitholder rights contained in our partnership agreement. We currently have seven directors serving on the board of directors. One of the members of Plains All American GP LLC, Sable Investments, L.P., has the right at any time to designate an eighth director. Because we are a limited partnership, the new listing standards of the New York Stock Exchange do not require that we or our general partner have a majority of independent directors or a nominating or compensation committee of the board of directors.

Non-management directors meet in executive session in connection with each regular board meeting. Each non-management director acts as presiding director at the regularly scheduled executive sessions, rotating alphabetically by last name.

Interested parties can communicate directly with non-management directors by mail in care of Tim Moore, General Counsel and Secretary or Sharon Spurlin, Director of Internal Audit, Plains All American Pipeline, L.P., 333 Clay Street, Suite 1600, Houston, Texas 77002. Such communications should specify the intended recipient or recipients. Commercial solicitations or communications will not be forwarded.

We have an audit committee that reviews our external financial reporting, engages our independent auditors and reviews the adequacy of our internal accounting controls. The Board of Directors has determined that (i) each member of our audit committee is "independent" under applicable New York Stock Exchange Rules and (ii) that each member of our audit committee is an "Audit Committee Financial Expert," as that term is defined in Item 401 of Regulation S-K. The members of our audit committee and other committees are indicated in the table below.

In determining the independence of the members of our audit committee, the Board of Directors considered the relationships described below:

Mr. Everardo Goyanes, the Chairman of our Audit Committee, is the Chief Executive Officer of Liberty Energy Corporation ("LEC"), a subsidiary of Liberty Mutual Insurance Company. Mr. Goyanes is an employee of Liberty Mutual Insurance Company. LEC makes investments in producing properties, from some of which Plains Marketing, L.P. buys the production. LEC does not operate the properties in which it invests. Plains Marketing pays the same amount per barrel to LEC that it pays to other interest owners in the properties. In 2004, the amount paid to LEC by Plains Marketing was approximately $1.1 million ($1.0 million net of severance taxes).

Mr. J. Taft Symonds, a member of our Audit Committee, is a director and the non-executive Chairman of the Board of Tetra Technologies, Inc. ("Tetra"). A subsidiary of Tetra owns crude oil producing properties, from some of which Plains Marketing buys the production. We paid approximately $11 million to the Tetra subsidiary in 2004. Until July 2004, Mr. Symonds was also a director of Plains Resources Inc., with whom Plains Marketing has a marketing arrangement. We paid approximately $28.3 million to Plains Resources in 2004, and recognized segment profit of approximately $0.1 million. Mr. Symonds was not and is not an officer of Tetra or Plains Resources, and does not participate in operational decision making, including decisions concerning selection of crude oil purchasers or entering into sales or marketing arrangements.

We have a compensation committee, which reviews and makes recommendations regarding the compensation for the executive officers and administers our equity compensation plans for officers and key employees. We also have a governance committee that periodically reviews our governance guidelines. In addition, our partnership agreement provides for the establishment/activation of a conflicts committee as circumstances warrant to review conflicts of interest between us and our general partner or the owners of our general partner. Such a committee would consist of a minimum of two members, none of whom can be officers or employees of our general partner or directors, officers or employees of its affiliates nor owners of the general partner's interest. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our general partner of any duties owed to us or our unitholders.

Our committee charters and governance guidelines, as well as our Code of Business Conduct and our Code of Ethics for Senior Financial Officers, are available on our website at www.paalp.com.

Directors and Executive Officers

The following table sets forth certain information with respect to the executive officers and members of the Board of Directors of our general partner. Directors are elected annually. Certain owners of our general partner each have the right to separately designate a member of our board. Such designees are indicated in the footnote to the following table.

Name	Age (as of 12/31/04)	Position with Our General Partner
Greg L. Armstrong(1)	46	Chairman of the Board, Chief Executive Officer and Director
Harry N. Pefanis	47	President and Chief Operating Officer
Phillip D. Kramer	48	Executive Vice President and Chief Financial Officer
George R. Coiner	54	Senior Group Vice President
W. David Duckett	49	President PMC (Nova Scotia) Company
Mark F. Shires	47	Senior Vice President Operations
Alfred A. Lindseth	35	Senior Vice President Technology, Process & Risk Management
Lawrence J. Dreyfuss	50	Vice President, Associate General Counsel and Assistant Secretary; Vice President, General Counsel and Secretary of PMC (Nova Scotia) Company (the general partner of Plains Marketing Canada, L.P.)
James B. Fryfogle	53	Vice President Refinery Supply
Jim G. Hester	45	Vice President Acquisitions
Tim Moore	47	Vice President, General Counsel and Secretary
Daniel J. Nerbonne	47	Vice President Engineering
John F. Russell	56	Vice President Pipeline Operations
Al Swanson	40	Vice President and Treasurer
Tina L. Val	35	Vice President Accounting and Chief Accounting Officer
Troy E. Valenzuela	43	Vice President Environmental, Health and Safety
John P. vonBerg	50	Vice President Trading
David N. Capobianco(1)	35	Director and Member of Compensation Committee
Everardo Goyanes	60	Director and Member of Audit* Committee
Gary R. Petersen(1)	58	Director and Member of Compensation* Committee
Robert V. Sinnott(1)	55	Director and Member of Compensation Committee
Arthur L. Smith	52	Director and Member of Audit and Governance* Committees
J. Taft Symonds	65	Director and Member of Governance and Audit Committees

* Indicates chairman of committee.

(1) The Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC (as amended, the "LLC Agreement") specifies that the Chief Executive Officer of the general partner will be a member of the board of directors. The LLC Agreement also provides that certain of the owners of our general partner have the right to designate a member of our board of directors. Mr. Capobianco has been designated by Plains Holdings Inc., which is owned by Vulcan Energy Corporation, of which he is Chairman of the board. Mr. Petersen has been designated by E-Holdings III, L.P., an affiliate of EnCap Investments L.P., of which he is a Managing Director. Sable Investments, L.P. has the right at any time to designate a director, but that seat is currently vacant. Sable Investments, L.P. is controlled by James M. Flores, a director of Vulcan Energy Corporation and also the Chairman, President and Chief Executive Officer of PXP. Mr. Sinnott has been designated by KAFU Holdings, L.P., which is affiliated with Kayne Anderson Investment Management, Inc., of which he is a Vice President. See "Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters Beneficial Ownership of General Partner Interest."

Greg L. Armstrong has served as Chairman of the Board and Chief Executive Officer since our formation. He has also served as a director of our general partner or former general partner since our formation. In addition, he was President, Chief Executive Officer and director of Plains Resources Inc. from 1992 to May 2001. He previously served Plains Resources as: President and Chief Operating Officer from October to December 1992; Executive Vice President and Chief Financial Officer from June to October 1992; Senior Vice President and Chief Financial Officer from 1991 to 1992; Vice

President and Chief Financial Officer from 1984 to 1991; Corporate Secretary from 1981 to 1988; and Treasurer from 1984 to 1987. Mr. Armstrong is also a director of Varco International, Inc.

Harry N. Pefanis has served as President and Chief Operating Officer since our formation. He was also a director of our former general partner. In addition, he was Executive Vice President Midstream of Plains Resources from May 1998 to May 2001. He previously served Plains Resources as: Senior Vice President from February 1996 until May 1998; Vice President Products Marketing from 1988 to February 1996; Manager of Products Marketing from 1987 to 1988; and Special Assistant for Corporate Planning from 1983 to 1987. Mr. Pefanis was also President of several former midstream subsidiaries of Plains Resources until our formation in 1998.

Phillip D. Kramer has served as Executive Vice President and Chief Financial Officer since our formation. In addition, he was Executive Vice President and Chief Financial Officer of Plains Resources from May 1998 to May 2001. He previously served Plains Resources as: Senior Vice President and Chief Financial Officer from May 1997 until May 1998; Vice President and Chief Financial Officer from 1992 to 1997; Vice President from 1988 to 1992; Treasurer from 1987 to March 2001; and Controller from 1983 to 1987.

George R. Coiner has served as Senior Group Vice President since February 2004 and as Senior Vice President from our formation to February 2004. In addition, he was Vice President of Plains Marketing & Transportation Inc., from November 1995 until our formation in 1998. Prior to joining Plains Marketing & Transportation Inc., he was Senior Vice President, Marketing with Scurlock Permian Corp.

W. David Duckett has been President of PMC (Nova Scotia) Company since June 2003, and Executive Vice President of PMC (Nova Scotia) Company from July 2001 to June 2003. Mr. Duckett was previously with CANPET Energy Group Inc. since 1985, where he served in various capacities, including most recently as President, Chief Executive Officer and Chairman of the Board.

Mark F. Shires has served as Senior Vice President Operations since June 2003 and as Vice President Operations from August 1999 to June 2003. He served as Manager of Operations from April 1999 to August 1999. In addition, he was a business consultant from 1996 until April 1999. He served as a consultant to Plains Marketing & Transportation Inc. and Plains All American Pipeline, LP from May 1998 until April 1999. He previously served as President of Plains Terminal & Transfer Corporation, from 1993 to 1996.

Alfred A. Lindseth has served as Senior Vice President Technology, Process & Risk Management since June 2003 and as Vice President Administration from March 2001 to June 2003. He served as Risk Manager from March 2000 to March 2001. He previously served PricewaterhouseCoopers LLP in its Financial Risk Management Practice section as a Consultant from 1997 to 1999 and as Principal Consultant from 1999 to March 2000. He also served GSC Energy, an energy risk management brokerage and consulting firm, as Manager of its Oil & Gas Hedging Program from 1995 to 1996 and as Director of Research and Trading from 1996 to 1997.

Lawrence J. Dreyfuss has served as Vice President, Associate General Counsel and Assistant Secretary of our general partner since February 2004 and as Associate General Counsel and Assistant Secretary of our general partner from June 2001 to February 2004 and held a senior management position in the Law Department since May 1999. In addition, he was a Vice President of Scurlock Permian LLC from 1987 to 1999.

James B. Fryfogle has served as a Vice President (currently Vice President Refinery Supply) since July 2004. Prior to joining us in January 2004, Mr. Fryfogle served as Manager of Crude Supply and Trading for Marathon Ashland Petroleum. Mr. Fryfogle had held numerous positions of increasing responsibility with Marathon Ashland Petroleum or its affiliates or predecessors since 1975.

Jim G. Hester has served as Vice President Acquisitions since March 2002. Prior to joining us, Mr. Hester was Senior Vice President Special Projects of Plains Resources. From May 2001 to December 2001, he was Senior Vice President Operations for Plains Resources. From May 1999 to May 2001, he was Vice President Business Development and Acquisitions of Plains Resources. He was Manager of Business Development and Acquisitions of Plains Resources from 1997 to May 1999, Manager of Corporate Development from 1995 to 1997 and Manager of Special Projects from 1993 to 1995. He was Assistant Controller from 1991 to 1993, Accounting Manager from 1990 to 1991 and Revenue Accounting Supervisor from 1988 to 1990.

Tim Moore has served as Vice President, General Counsel and Secretary since May 2000. In addition, he was Vice President, General Counsel and Secretary of Plains Resources from May 2000 to May 2001. Prior to joining Plains Resources, he served in various positions, including General Counsel Corporate, with TransTexas Gas Corporation from 1994 to 2000. He previously was a corporate attorney with the Houston office of Weil, Gotshal & Manges LLP. Mr. Moore also has seven years of energy industry experience as a petroleum geologist.

John F. Russell has served as Vice President Pipeline Operations since July 2004. Prior to joining PAA, Mr. Russell served as Vice President of Business Development & Joint Interest for ExxonMobil Pipeline Company. Mr. Russell had held numerous positions of increasing responsibility with ExxonMobil Pipeline Company or its affiliates or predecessors since 1974.

Daniel J. Nerbonne has served as Vice President Engineering since February 2005. Prior to joining us, Mr. Nerbonne was General Manager of Portfolio Projects for Shell Oil Products US from January 2004 to January 2005 and served in various capacities, including General Manager of Commercial and Joint Interest, with Shell Pipeline Company or its predecessors from 1998. From 1980 to 1998 Mr. Nerbonne held numerous positions of increasing responsibility in engineering, operations, and business development, including Vice President of Business Development from December 1996 to April 1998, with Texaco Trading and Transportation or its affiliates.

Al Swanson has served as Vice President and Treasurer since February 2004 and as Treasurer from May 2001 to February 2004. In addition, he held finance related positions at Plains Resources including Treasurer from February 2001 to May 2001 and Director of Treasury from November 2000 to February 2001. Prior to joining Plains Resources, he served as Treasurer of Santa Fe Snyder Corporation from 1999 to October 2000 and in various capacities at Snyder Oil Corporation including Director of Corporate Finance from 1998, Controller SOCO Offshore, Inc. from 1997, and Accounting Manager from 1992. Mr. Swanson began his career with Apache Corporation in 1986 serving in internal audit and accounting.

Tina L. Val has served as Vice President Accounting and Chief Accounting Officer since June 2003. She served as Controller from April 2000 until she was elected to her current position. From January 1998 to January 2000, Ms. Val served as a consultant to Conoco de Venezuela S.A. She previously served as Senior Financial Analyst for Plains Resources from October 1994 to July 1997.

Troy E. Valenzuela has served as Vice President Environmental, Health and Safety, or EH&S, since July 2002, and has had oversight responsibility for the environmental, safety and regulatory compliance efforts of us and our predecessors for the last 12 years. He was Director of EH&S with Plains Resources from January 1996 to June 2002, and Manager of EH&S from July 1992 to December 1995. Prior to his time with Plains Resources, Mr. Valenzuela spent seven years with Chevron USA Production Company in various EH&S roles.

John P. vonBerg has served as Vice President of Trading since May 2003 and Director of these activities since joining us in January of 2002. He was with Genesis Energy in differing capacities as a Director, Vice Chairman, President and CEO from 1996 through 2001, and from 1993 to 1996 he served as a Vice President and a Crude Oil Manager for Phibro Energy USA. Mr. VonBerg began his career with Marathon Oil Company, spending 13 years in various disciplines.

David N. Capobianco has served as a director of our general partner since July 2004. Mr. Capobianco is Chairman of the board of directors of Vulcan Energy Corporation and a Managing Director of Vulcan Capital, an affiliate of Vulcan Inc., where he has been employed since April 2003. Previously, he served as a Vice President of Greenhill Capital from July 2001 to April 2003 and a Vice President of Harvest Partners from July 1995 to January 2001.

Everardo Goyanes has served as a director of our general partner or former general partner since May 1999. Mr. Goyanes has been President and Chief Executive Officer of Liberty Energy Holdings LLC (an energy investment firm) since May 2000. From 1999 to May 2000, he was a financial consultant specializing in natural resources. From 1989 to 1999, he was Managing Director of the Natural Resources Group of ING Barings Furman Selz (a banking firm). He was a financial consultant from 1987 to 1989 and was Vice President Finance of Forest Oil Corporation from 1983 to 1987. Mr. Goyanes received a BA in Economics from Cornell University and a Masters degree in Finance (honors) from Babson Institute.

Gary R. Petersen has served as a director since June 2001. Mr. Petersen co-founded EnCap Investments L.P. (an investment management firm) and has been a Managing Director and principal of the firm since 1988. He had previously served as Senior Vice President and Manager of the Corporate Finance Division of the Energy Banking Group for RepublicBank Corporation. Prior to his position at RepublicBank, he was Executive Vice President and a member of the Board of Directors of Nicklos Oil & Gas Company in Houston, Texas from 1979 to 1984. He served from 1970 to 1971 in the U.S. Army as a First Lieutenant in the Finance Corps and as an Army Officer in the National Security Agency. He is also a director of Equus II Incorporated.

Robert V. Sinnott has served as a director of our general partner or former general partner since September 1998. Mr. Sinnott serves as the President and Chief Investment Officer of Kayne Anderson Capital Advisors, L.P. (an investment management firm), where he has served in various capacities, including Senior Managing Director and Managing Director, since 1992. He is also a vice president of Kayne Anderson Investment Management, Inc., the general partner of Kayne Anderson Capital Advisors, L.P. He was Vice President and Senior Securities Officer of the Investment Banking Division of Citibank from 1986 to 1992. Mr. Sinnott was previously a director of Plains Resources.

Arthur L. Smith has served as a director of our general partner or former general partner since February 1999. Mr. Smith is Chairman and CEO of John S. Herold, Inc. (a petroleum research and consulting firm), a position he has held since 1984. From 1976 to 1984 Mr. Smith was a securities analyst with Argus Research Corp., The First Boston Corporation and Oppenheimer & Co., Inc. Mr. Smith has prior public board experience with Pioneer Natural Resources, Cabot Oil & Gas Corporation and Evergreen Resources, Inc. Mr. Smith holds the CFA designation. He serves on the board of non-profit Dress for Success Houston and the Board of Visitors for the Duke Nicholas School of the Environment and Earth Sciences. Mr. Smith received a BA from Duke University and an MBA from NYU's Stern School of Business.

J. Taft Symonds has served as a director since June 2001. Mr. Symonds is Chairman of the Board of Symonds Trust Co. Ltd. (an investment firm) and Chairman of the Board of Tetra Technologies, Inc. (an oilfield services firm). From 1978 to 2004 he was Chairman of the Board and Chief Financial Officer of Maurice Pincoffs Company, Inc. (an international marketing firm). Mr. Symonds was previously a director of Plains Resources. Mr. Symonds has a background in both investment and commercial banking, including merchant banking in New York, London and Hong Kong with Paine Webber Jackson & Curtis, Robert Fleming Group and Banque de la Societe Financiere Europeenne. He is a director of Intercorr International and President of the Houston Arboretum and Nature Center. Mr. Symonds received a BA from Stanford University and an MBA from Harvard.

Management Team/Canadian Officers

The following table sets forth certain information with respect to other members of our management team and officers of the general partner of our Canadian operating partnership.

Name	Age (as of 12/31/04)	Position with Our General Partner/ Canadian General Partner
Management Team:		
A. Patrick Diamond	32	Manager Special Projects
Canadian Officers:		
D. Mark Alenius	45	Vice President and Chief Financial Officer of PMC (Nova Scotia) Company
Stephen L. Bart	44	Vice President Operations of PMC (Nova Scotia) Company
Ralph R. Cross	49	Vice President Business Development of PMC (Nova Scotia) Company
M.D. (Mike) Hallahan	44	Vice President Crude Oil of PMC (Nova Scotia) Company
Richard (Rick) Henson	50	Vice President Corporate Services of PMC (Nova Scotia) Company
Ron F. Wunder	36	Vice President LPG of PMC (Nova Scotia) Company

A. Patrick Diamond has served as Manager Special Projects since June 2001. In addition, he was Manager Special Projects of Plains Resources from August 1999 to June 2001. Prior to joining Plains Resources, Mr. Diamond served Salomon Smith Barney Inc. in its Global Energy Investment Banking Group as an Associate from July 1997 to May 1999 and as a Financial Analyst from July 1994 to June 1997.

D. Mark Alenius has served as Vice President and Chief Financial Officer of PMC (Nova Scotia) Company since November 2002. In addition, Mr. Alenius was Managing Director, Finance of PMC (Nova Scotia) Company from July 2001 to November 2002. Mr. Alenius was previously with CANPET Energy Group Inc. where he served as Vice President, Finance, Secretary and Treasurer, and was a member of the Board of Directors. Mr. Alenius joined CANPET in February 2000. Prior to joining CANPET Energy, Mr. Alenius briefly served as Chief Financial Officer of Bromley-Marr ECOS Inc., a manufacturing and processing company, from January to July 1999. Mr. Alenius was previously with Koch Industries, Inc.'s Canadian group of businesses, where he served in various capacities, including most recently as Vice-President, Finance and Chief Financial Officer of Koch Pipelines Canada, Ltd.

Stephen L. Bart has been Vice President, Operations of PMC (Nova Scotia) Company since April 2005 and was Managing Director, LPG Operations & Engineering from February to April 2005. From June 2003 to February 2005, Mr. Bart was engaged as a principal of Broad Quay Development, a consulting firm. From April 2001 to June 2003, Mr. Bart served as Chief Executive Officer of Novera Energy Limited, a publicly-traded international renewable energy concern. From January 2000 to April 2003, he served as Director, Northern Development, for Westcoast Energy Inc.

Ralph R. Cross has been Vice President of Business Development of PMC (Nova Scotia) Company since July 2001. Mr. Cross was previously with CANPET Energy Group Inc. since 1992, where he served in various capacities, including most recently as Vice President of Business Development.

M.D. (Mike) Hallahan has served as Vice President, Crude Oil of PMC (Nova Scotia) Company since February 2004 and Managing Director, Facilities from July, 2001 to February, 2004. He was previously with CANPET Energy Group Inc. where he served in various capacities since 1996, most recently General Manager, Facilities.

Richard (Rick) Henson joined PMC (Nova Scotia) Company in December 2004 as Vice President of Corporate Services. Mr. Henson was previously with Nova Chemicals Corporation, serving in various executive positions from 1999 through 2004, including Vice President, Petrochemicals and Feedstocks, and Vice President, Ethylene and Petrochemicals Business.

Ron F. Wunder has served as Vice President, LPG of PMC (Nova Scotia) Company since February 2004 and as Managing Director, Crude Oil from July 2001 to February 2004. He was previously with CANPET Energy Group Inc. since 1992, where he served in various capacities, including most recently as General Manager, Crude Oil.

Executive Compensation

The following table sets forth certain compensation information for our Chief Executive Officer and the four other most highly compensated executive officers in 2004 (the "Named Executive Officers"). We reimburse our general partner and its affiliates for expenses incurred on our behalf, including the costs of officer compensation. The Named Executive Officers have also received certain equity-based awards from our general partner, which awards (other than awards under the Long-Term Incentive Plans) are not subject to reimbursement by us. See " Long-Term Incentive Plan" and "Certain Relationships and Related Transactions Transactions with Related Parties."

		Annual Compensation		Long-Term Compensation	
Name and Principal Position	**Year**	**Salary**	**Bonus**	**LTIP Payout**	**All Other Compensation**
Greg L. Armstrong	2004	$ 330,000	$ 1,800,000	$ 1,692,600	$ 13,930[1]
Chairman and CEO	2003	330,000	1,000,000		12,930
	2002	330,000	600,000		11,930
Harry N. Pefanis	2004	$ 235,000	$ 1,500,000	$ 1,674,600	$ 13,875[1]
President and COO	2003	235,000	800,000	452,400	12,875
	2002	235,000	475,000		11,875
Phillip D. Kramer	2004	$ 200,000	$ 850,000	$ 1,209,000	$ 13,745[1]
Executive V.P. and CFO	2003	200,000	500,000		12,745
	2002	200,000	275,000		11,745
George R. Coiner	2004	$ 200,000	$ 1,061,000[2]	$ 1,643,138	$ 13,730[1]
Senior Group Vice President	2003	200,000	719,600[2]	226,200	12,730
	2002	200,000	451,000[2]		11,651
W. David Duckett[3]	2004	$ 204,161	$ 933,505[4]	$	$ 26,541[5]
President PMC	2003	190,658	724,883[4]		
(Nova Scotia Company)	2002	163,891	270,070[4]		

(1) Our general partner matches 100% of employees' contributions to its 401(k) Plan in cash, subject to certain limitations in the plan. Includes $13,000 in such contributions for 2004. The remaining amount represents premium payments on behalf of the Named Executive Officer for group term life insurance. The amount shown does not include the value of perquisites and other benefits because they do not exceed $50,000 in the aggregate.

(2) Includes quarterly bonuses aggregating $561,000, $469,600 and $361,000 and an annual bonus of $500,000, $250,000 and $90,000 for 2004, 2003 and 2002, respectively. The annual bonuses are payable 60% at the time of award and 20% in each of the two succeeding years. For the quarterly bonuses, Mr. Coiner participates in a quarterly bonus arrangement based on EBITDA from our commercial activities during the quarter. Other participants include approximately 73 employees in the marketing and business development group. For 2004, the quarterly bonus pool totaled approximately $4.4 million.

(3) Salary and bonus for Mr. Duckett are presented in U.S. dollar equivalent, based on the exchange rates in effect on the dates payments were made.

(4) The 2004 bonus amount includes $798,151 under a bonus program established at the time of the CANPET acquisition and $135,354 under a special 2004 retention bonus associated with the CANPET acquisition. Under the bonus program at PMC (Nova Scotia) Company established at the time of the CANPET purchase, all employees of PMC (Nova Scotia) Company are eligible to participate. The plan is based on EBITDA, and includes a quarterly bonus pool consisting of 4% of quarterly EBITDA and an annual bonus pool consisting of 6% of EBITDA.

(5) Employer contributions to PMC (Nova Scotia) Company savings plan.

Employment Contracts and Termination of Employment and Change-in-Control Arrangements

Messrs. Armstrong and Pefanis have employment agreements with our general partner. Mr. Armstrong is employed as Chairman and Chief Executive Officer. The initial three-year term of Mr. Armstrong's employment agreement commenced on June 30, 2001, and is automatically extended for one year on June 30 of each year (such that the term is reset to three years) unless Mr. Armstrong receives notice from the Chairman of the Compensation Committee that the Board of Directors has elected not to extend the agreement. Mr. Armstrong has agreed, during the term of the agreement and for five years thereafter, not to disclose (subject to typical exceptions) any confidential information obtained by him while employed under the agreement. The agreement provided for a base salary of $330,000 per year, subject to annual review. In February 2005, the annual salary was increased to $375,000. If Mr. Armstrong's employment is terminated without cause, he will be entitled to receive an amount equal to his annual base salary plus his highest annual bonus, multiplied by the lesser of (i) the number of years (including fractional years) remaining on the agreement and (ii) two. If Mr. Armstrong terminates his employment as a result of a change in control he will be entitled to receive an amount equal to three times the aggregate of his annual base salary and highest annual bonus. Under Mr. Armstrong's agreement, a "change of control" is defined to include (i) the acquisition by an entity or group (other than Plains Resources and its wholly owned subsidiaries) of 50% or more of our general partner or (ii) the existing owners of our general partner ceasing to own more than 50% of our general partner. If Mr. Armstrong's employment is terminated because of his death, a lump sum payment will be paid to his designee equal to his annual salary plus his highest annual bonus, multiplied by the lesser of (i) the number of years (including fractional years) remaining on the agreement and (ii) two. Under the agreement, Mr. Armstrong will be reimbursed for any excise tax due as a result of compensation (parachute) payments.

Mr. Pefanis is employed as President and Chief Operating Officer. The initial three-year term of Mr. Pefanis' employment agreement commenced on June 30, 2001, and is automatically extended for one year on June 30 of each year (such that the term is reset to three years) unless Mr. Pefanis receives notice from the Chairman of the Board of Directors that the Board has elected not to extend the agreement. Mr. Pefanis has agreed, during the term of the agreement and for one year thereafter, not to disclose (subject to typical exceptions) any confidential information obtained by him while employed under the agreement. The agreement provided for a base salary of $235,000 per year, subject to annual review. In February 2005, the annual salary was increased to $300,000. The provisions in

Mr. Pefanis' agreement with respect to termination, change in control and related payment obligations are substantially similar to the parallel provisions in Mr. Armstrong's agreement.

1998 Long-Term Incentive Plan

Our general partner has adopted the Plains All American GP LLC 1998 Long-Term Incentive Plan (the "1998 LTIP") for employees and directors of our general partner and its affiliates who perform services for us. Awards contemplated by the 1998 LTIP include phantom units and unit options. The 1998 LTIP currently permits the grant of phantom units and unit options covering an aggregate of 1,425,000 common units delivered upon vesting of such phantom units or unit options. No options have been granted under the plan. The plan is administered by the Compensation Committee of our general partner's board of directors. Our general partner's board of directors has the right to alter or amend the 1998 LTIP or any part of the plan from time to time, including, subject to any applicable NYSE listing requirements, increasing the number of common units with respect to which awards may be granted; provided, however, that no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of such participant.

Common units to be delivered upon the vesting of rights may be common units acquired by our general partner in the open market or in private transactions, common units already owned by our general partner, or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the cost incurred in acquiring common units. In addition, over the term of the plan we may issue new common units to satisfy delivery obligations under the grants. When we issue new common units upon vesting of grants, the total number of common units outstanding increases.

Phantom Units. A phantom unit entitles the grantee to receive, upon the vesting of the phantom unit, a common unit (or cash equivalent, depending on the terms of the grant). A substantial number of phantom units have vested in 2003 and 2004. As of May 16, 2005, giving effect to vested grants, grants of approximately 59,000 unvested phantom units under the 1998 LTIP remain outstanding to employees, officers and directors of our general partner. The Compensation Committee may, in the future, make additional grants under the plan to employees and directors containing such terms as the Compensation Committee shall determine, including tandem distribution equivalent rights with respect to phantom units.

Other than grants to directors (discussed below), none of the phantom units vested until November 2003. Since that time, approximately 1,000,000 phantom units have vested. Including grants to directors, approximately 464,000 units have been purchased and delivered or issued in satisfaction of vesting, after payment of cash-equivalents and netting for taxes. As a result of the vesting of these awards, we recognized an expense of approximately $28.8 million during 2003 and an additional expense of approximately $7.9 million during 2004.

The issuance of the common units upon vesting of phantom units is primarily intended to serve as a means of incentive compensation for performance. Therefore, no consideration is paid to us by the plan participants upon receipt of the common units.

For information on grants to directors, see " Compensation of Directors."

The following table shows the vesting of phantom units granted under the 1998 LTIP to the Named Executive Officers.

Name	Total Units	2003 Vesting Units	2003 Vesting Value(1)	2004 Vesting Units	2004 Vesting Value(1)	2005 Vesting Units	2005 Vesting Value(1)
Greg L. Armstrong	70,000			52,500	$ 1,692,600	17,500	$ 701,575
Harry N. Pefanis	70,000	15,000	$ 452,400	52,500	$ 1,674,600	2,500	$ 100,225
Phillip D. Kramer	50,000			37,500	$ 1,209,000	12,500	$ 501,125
George R. Coiner	67,500	7,500	$ 226,200	50,625	$ 1,643,138	9,375	$ 375,844
W. David Duckett							

(1) As of vesting dates.

Unit Option Plan. The unit option plan under our 1998 LTIP currently permits the grant of options covering common units. No grants have been made under the unit option plan to date.

However, the Compensation Committee may, in the future, make grants under the plan to employees and directors containing such terms as the committee shall determine, provided that unit options have an exercise price equal to the fair market value of the units on the date of grant.

2005 Long-Term Incentive Plan

In January 2005, our unitholders approved the 2005 Plains All American GP LLC Long-Term Incentive Plan (the "2005 LTIP"). The 2005 LTIP provides for awards to our employees and directors. Awards contemplated by the 2005 LTIP include phantom units, restricted units, unit appreciation rights and unit options, as determined by the Compensation Committee (each an "Award"). Up to 3,000,000 units may be issued in satisfaction of Awards. Certain Awards may also include, in the discretion of the Compensation Committee, a "distribution equivalent right," or "DER," that entitles the grantee to a cash payment, either while the Award is outstanding or upon vesting, equal to any cash distributions paid on a unit while the Award is outstanding.

Common units to be delivered upon the vesting of rights may be common units acquired by our general partner in the open market or in private transactions, common units already owned by our general partner, or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the cost incurred in acquiring common units. In addition, over the term of the plan we may issue new common units to satisfy delivery obligations under the grants. When we issue new common units upon vesting of grants, the total number of common units outstanding increases.

The Compensation Committee and Board of Directors have approved grants under the 2005 LTIP of phantom units with associated DERs to the Named Executive Officers as follows: Mr. Armstrong 300,000 phantom units; Mr. Pefanis 200,000 phantom units; Mr. Kramer 100,000 phantom units; Mr. Coiner 80,000 phantom units; and Mr. Duckett 75,000 phantom units. The phantom units for Messrs Armstrong and Pefanis will vest incrementally solely upon achievement by the Partnership of annualized distributions of $2.60, $2.80 and $3.00 per unit and continued employment of at least 2, 4 and 5 years, respectively and any phantom units unvested after seven years will be forfeited. The phantom units granted to Messrs Kramer, Coiner and Duckett are also subject to incremental vesting upon attainment of similar distribution thresholds and similar minimum years of continued employment, provided however that any remaining unvested units will fully vest after six years.

The issuance of the common units upon vesting of phantom units is primarily intended to serve as a means of incentive compensation for performance. Therefore, no consideration is paid to us by the plan participants upon receipt of the common units.

Other Equity Grants

Certain other employees and officers have also received grants of equity not associated with the LTIP's described above, and for which we have no direct cost or reimbursement obligations. For example, in 2001 our general partner established a Performance Option Plan funded by common units owned by the general partner. See "Certain Relationships and Related Transactions Transactions with Related Parties."

New tax rules concerning deferred compensation became effective January 1, 2005. We intend to operate all of our equity plans, and make any amendments thereto that may be necessary, for the plans and awards granted thereunder to comply with this new law.

Compensation of Directors

Each director of our general partner who is not an employee of our general partner is reimbursed for any travel, lodging and other out-of-pocket expenses related to meeting attendance or otherwise related to service on the board (including, without limitation, reimbursement for continuing education expenses). Each non-employee director is currently paid an annual retainer fee of $45,000. In 2001, Messrs. Goyanes and Smith each received $10,000 for their service on a special committee of the Board of Directors of our former general partner. Mr. Armstrong is otherwise compensated for his services as an employee and therefore receives no separate compensation for his services as a director. Each committee chairman (other than the Audit Committee) receives $2,000 annually. The chairman of the Audit Committee receives $30,000 annually, and the other members of the Audit Committee receive $15,000 annually. Mr. Petersen assigns any compensation he receives in his capacity as a director to EnCap Energy Capital Fund III, L.P. (EnCap III), which is controlled by EnCap Investments L.P., of which Mr. Petersen is a Managing Director. Mr. Capobianco assigns any compensation he receives in his capacity as a director to Vulcan Capital.

Except as described below, each non-employee director has received an LTIP award of 5,000 units in the aggregate. These units vest annually in 25% increments, subject to an automatic re-grant of the amount vested, such that the director will always have outstanding an award of 5,000 units. For Mr. Peterson and Mr. Capobianco, a cash equivalent payment will be made to EnCap III and Vulcan Capital, respectively, upon any vesting. The units vest in full upon the death or disability (as determined by the board) of the director. For any "independent" directors (as defined in the Third Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC, as amended, and currently including Messrs. Goyanes, Smith and Symonds), the units will also vest in full if such director (i) retires (no longer with full-time employment and no longer serving as an officer or director of any public company) or (ii) is removed from the Board or is not reelected to the Board, unless such removal or failure to reelect is for "good cause," as defined in the letter granting the phantom units.

Reimbursement of Expenses of Our General Partner and its Affiliates

We do not pay our general partner a management fee, but we do reimburse our general partner for all expenses incurred on our behalf, including the costs of employee, officer and director compensation and benefits, as well as all other expenses necessary or appropriate to the conduct of our business. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion. See "Certain Relationships and Related Transactions."

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED UNITHOLDERS' MATTERS

Beneficial Ownership of Limited Partner Interest

Our common units outstanding represent 98% of our equity (limited partner interest). The 2% general partner interest is discussed separately below under the caption "Beneficial Ownership of General Partner Interest." The following table sets forth the beneficial ownership of limited partner units held by beneficial owners of 5% or more of the units, by directors and the Chief Executive Officer and the four other most highly compensated executive officers in 2004 (the "Named Executive Officers") of our general partner and by all directors and executive officers as a group as of May 16, 2005.

Name of Beneficial Owner	Common Units	Percentage of Common Units(1)
Paul G. Allen	13,688,400(2)	20.2%
Vulcan Energy Corporation	12,390,120(3)	18.2%
Richard Kayne/Kayne Anderson Capital Advisors, L.P.	5,591,121(4)	8.2%
Greg L. Armstrong	243,863(5)(6)(7)	(8)
Harry N. Pefanis	160,365(6)(7)	(8)
George R. Coiner	64,901(6)(7)	(8)
Phillip D. Kramer	109,247(6)(7)	(8)
W. David Duckett	119,541	(8)
David N. Capobianco	(9)	(8)
Everardo Goyanes	8,700(6)	(8)
Gary R. Petersen	5,700(10)	(8)
Robert V. Sinnott	15,000(6)(11)	(8)
Arthur L. Smith	11,250(6)	(8)
J. Taft Symonds	20,000(6)	(8)
All directors and executive officers as a group (23 persons)	969,262(6)(7)	1.4%

(1) Limited partner units constitute 98% of our equity, with the remaining 2% held by our general partner. Amounts shown include the 575,000 units issued in a private placement on February 25, 2005 to Plains Holdings II Inc. The beneficial ownership of our general partner is set forth in the table below under the caption "Beneficial Ownership of General Partner Interest." Giving effect to the indirect ownership by Vulcan Energy Corporation of a portion of our general partner, Mr. Allen may be deemed to beneficially own approximately 20.6% of our total equity. Mr. Allen disclaims any deemed beneficial ownership, beyond his pecuniary interest, in any of our partner interests held by Vulcan Energy Corporation or any of its affiliates.

(2) Mr. Allen owns approximately 88.38% of the outstanding shares of common stock of Vulcan Energy Corporation. Vulcan Energy Corporation is the indirect sole stockholder of Plains Holdings Inc. See Note 3 below. Mr. Allen also controls Vulcan Capital Private Equity I LLC ("Vulcan LLC"), which is the record holder of 1,298,280 common units. The address for Mr. Allen, Vulcan Energy Corporation and Vulcan LLC is 505 Fifth Avenue S, Suite 900, Seattle, Washington 98104. Mr. Allen disclaims any deemed beneficial ownership, beyond his pecuniary interest, in any of our partner interests held by Vulcan Energy or any of its affiliates.

(3) Vulcan Energy Corporation is the indirect sole stockholder of Plains Holdings Inc., our former general partner. The common units are owned by Plains Holdings Inc. and its wholly owned subsidiary, Plains Holdings II Inc. The address for Plains Holdings Inc. and Plains Holdings II Inc. is 700 Louisiana, Suite 4150, Houston, Texas 77002.

(4) Richard A. Kayne is President, Chief Executive Officer and Director of Kayne Anderson Investment Management, Inc., which is the general partner of Kayne Anderson Capital Advisors, L.P. ("KACALP"). Various accounts (including KAFU Holdings, L.P., which owns a portion of our general partner) under the management or control of KACALP own 5,355,391 common units. Mr. Kayne may be deemed to beneficially own such units. In addition, Mr. Kayne directly owns or has sole voting and dispositive power over 235,730 common units. Mr. Kayne disclaims beneficial ownership of any of our partner interests other than units held by him or interests attributable to him by virtue of his interests in the accounts that own our partner interests. The address for Mr. Kayne and Kayne Anderson Investment Management Inc. is 1800 Avenue of the Stars, 2nd Floor, Los Angeles, California 90067.

(5) Does not include the common units owned by our general partner in connection with the Performance Option Plan. Mr. Armstrong disclaims any beneficial ownership of such units beyond his rights as a grantee under the plan. See "Certain Relationships and Related Transactions Transactions with Related Parties Performance Option Plan."

(6) Includes phantom units granted under the 1998 LTIP that vested and were issued to officers in May 2005 and unvested phantom units expected to vest and be delivered to directors in June 2005. See "Management 1998 Long-Term Incentive Plan."

(7) Includes the following vested, unexercised options to purchase common units under the Performance Option Plan. Mr. Armstrong: 56,250; Mr. Pefanis: 41,250; Mr. Coiner: 31,875; Mr. Kramer: 33,750; directors and officers as a group: 238,125.

(8) Less than one percent.

(9) The Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC (the "LLC Agreement") specifies that certain of the owners of our general partner have the right to designate a member of our board of directors. Mr. Capobianco has been designated by Plains Holdings Inc., a wholly owned subsidiary of Plains Resources, of which he is a director and Vice President. Mr. Capobianco is also the Chairman and a Vice President of Vulcan Energy Corporation. Mr. Capobianco has the right to receive a performance-based fee based on the performance of the holdings of Vulcan Energy Corporation. Mr. Capobianco disclaims any deemed beneficial ownership of our partner interests held by Vulcan Energy Corporation or any of its affiliates beyond his pecuniary interest therein, if any. Mr. Capobianco owns an equity interest in, and has an indirect right to receive a performance-based fee based on the performance of the holdings of, Vulcan Capital Private Equity I LLC. Mr. Capobianco disclaims any deemed beneficial ownership of the units held by Vulcan Capital Private Equity I LLC beyond his pecuniary interest therein, if any.

(10) Pursuant to the LLC Agreement, Mr. Petersen has been designated by E-Holdings III, L.P., an affiliate of EnCap Investments L.P., of which he is a Managing Director. Mr. Petersen disclaims any deemed beneficial ownership of any of our partner interests owned by E-Holdings III, L.P. or other affiliates of EnCap Investments L.P. beyond his pecuniary interest. The address for E-Holdings III, L.P. is 1100 Louisiana, Suite 3150, Houston, Texas 77002.

(11) Pursuant to the LLC Agreement, Mr. Sinnott has been designated one of our directors by KAFU Holdings, L.P., which is controlled by Kayne Anderson Investment Management, Inc., of which he is a Vice President. Mr. Sinnott disclaims any deemed beneficial ownership of any units held by KAFU Holdings, L.P. or its affiliates, other than through his 4.5% limited partner interest in KAFU Holdings, L.P. The address for KAFU Holdings, L.P. is 1800 Avenue of the Stars, 2nd Floor, Los Angeles, California 90067.

Beneficial Ownership of General Partner Interest

Plains AAP, L.P. owns all of our 2% general partner interest and all of our incentive distribution rights. The following table sets forth the effective ownership of Plains AAP, L.P. (after giving effect to proportionate ownership of Plains All American GP LLC, its 1% general partner).

Name and Address of Owner	Percentage Ownership of Plains AAP
Paul G. Allen[(1)] 505 Fifth Avenue S, Suite 900 Seattle, Washington 98104	44.000%
Vulcan Energy Corporation[(2)] 777 Walker, Suite 2400 Houston, TX 77002	44.000%
Sable Investments, L.P. 700 Milam, Suite 3100 Houston, TX 77002	20.000%
KAFU Holdings, L.P.[(3)] 1800 Avenue of the Stars, 2nd Floor Los Angeles, CA 90067	16.418%
E-Holdings III, L.P.[(4)] 1100 Louisiana, Suite 3150 Houston, TX 77002	9.000%
PAA Management, L.P.[(5)] 333 Clay Street, #1600 Houston, TX 77002	4.000%
Wachovia Investors, Inc 301 South College Street, 12th Floor Charlotte, NC 28288	3.382%
Mark E. Strome 100 Wilshire Blvd., Suite 1500 Santa Monica, CA 90401	2.134%
Strome Hedgecap Fund, L.P 100 Wilshire Blvd., Suite 1500 Santa Monica, CA 90401	1.066%

(1) Mr. Allen owns approximately 88.38% of the outstanding shares of common stock of Vulcan Energy Corporation. Vulcan Energy Corporation, through its wholly owned subsidiary, Plains Holdings Inc., owns 44% of the equity of our general partner. Mr. Allen disclaims any deemed beneficial ownership, beyond his pecuniary interest, in any of our partner interests held by Vulcan Energy Corporation or any of its affiliates.

(2) Mr. Capobianco disclaims any deemed beneficial ownership of the interests held by Vulcan Energy Corporation beyond his pecuniary interest therein, if any.

(3) Mr. Sinnott disclaims any deemed beneficial ownership of the interests owned by KAFU Holdings, L.P. other than through his 4.5% limited partner interest in KAFU Holdings, L.P.

(4) Mr. Petersen disclaims any deemed beneficial ownership of the interests owned by E-Holdings III, L.P. beyond his pecuniary interest.

(5)

PAA Management, L.P. is owned entirely by certain members of senior management, including Messrs. Armstrong (approximately 26%), Pefanis (approximately 14.5%), Kramer (approximately 9.5%), Coiner (approximately 9.5%) and

Duckett (approximately 4.5%). Other than Mr. Armstrong, no directors own any interest in PAA Management, L.P. Directors and executive officers as a group own approximately 95% of PAA Management, L.P. Mr. Armstrong disclaims any beneficial ownership of the general partner interest owned by Plains AAP, L.P., other than through his ownership interest in PAA Management, L.P.

Equity Compensation Plan Information

Plan Category	Number of Units to be Issued upon Exercise/Vesting of Outstanding Options, Warrants and Rights*	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights*	Number of Units Remaining Available for Future Issuance under Equity Compensation Plans*
	(a)	(b)	(c)
Equity compensation plans approved by unitholders:			
1998 Long Term Incentive Plan	59,400[(1)]	N/A[(2)]	487,858[(1)(3)]
2005 Long Term Incentive Plan	1,873,900[(4)]	N/A[(2)]	1,126,100[(3)]
Equity compensation plans not approved by unitholders:			
1998 Long Term Incentive Plan	[(1)(5)]	N/A[(2)]	[(6)]
Performance Option Plan	[(7)]	14.91[(8)]	[(7)]

*
As of May 16, 2005.

(1)
As originally instituted by our former general partner prior to our initial public offering, the 1998 LTIP contemplated issuance of up to 975,000 common units to satisfy awards of phantom units. Upon vesting, these awards could be satisfied either by (i) primary issuance of units by us or (ii) cash settlement or purchase of units by our general partner with the cost reimbursed by us. In 2000, the 1998 LTIP was amended, as provided in the plan, without unitholder approval, to increase the maximum awards to 1,425,000 phantom units; however, we can issue no more than 975,000 new units to satisfy the awards. Any additional units must be purchased by our general partner in the open market or in private transactions and be reimbursed by us. As of May 16, 2005, we have issued approximately 428,000 common units in satisfaction of vesting under the 1998 LTIP. The number of units presented in column (a) assumes that all remaining grants will be satisfied by the issuance of new units upon vesting. In fact, a substantial number of phantom units that vested in 2003 and 2004 were satisfied without the issuance of units. These phantom units were settled in cash or withheld for taxes. See "Management 1998 Long-Term Incentive Plan." Any units not issued upon vesting become "available for future issuance" under column (c).

(2)
Phantom unit awards under the 1998 LTIP vest without payment by recipients. See "Management 1998 Long-Term Incentive Plan."

(3)
In accordance with Item 201(d) of Regulation S-K, this column (c) excludes the securities disclosed in column (a). However, as discussed in footnote (1) above, any phantom units represented in column (a) that are not satisfied by the issuance of units become "available for future issuance." See "Management 1998 Long-Term Incentive Plan."

(4)
The 2005 Long Term Incentive Plan was approved by our unitholders in January 2005.

(5)
Although awards for units may from time to time be outstanding under the portion of the 1998 LTIP not approved by unitholders, all of these awards must be satisfied in cash or out of units purchased by our general partner and reimbursed by us. None will be satisfied by "units issued upon exercise/vesting."

(6)
Awards for up to 413,750 phantom units may be granted under the portion of the 1998 LTIP not approved by unitholders; however, no common units are "available for future issuance" under the plan, because all such awards must be satisfied with cash or out of units purchased by our general partner and reimbursed by us.

(7)
Our general partner has adopted and maintains a Performance Option Plan for officers and key employees pursuant to which optionees have the right to purchase units from the general partner. The units that will be sold under the plan were contributed to the general partner by certain of its owners in connection with the transfer of a majority of our general partner interest in 2001 without economic cost to the Partnership. Thus, there will be no units "issued upon exercise/vesting of outstanding options." All available units are currently subject to outstanding grants. See " Other Equity Grants."

(8)

As of May 16, 2005, the strike price for all outstanding options under the Performance Option Plan was $14.91 per unit. The strike price decreases as distributions are paid. Future grants may include different pricing elements. See "   Other Equity Grants."

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Our General Partner

Our operations and activities are managed by, and our officers and personnel are employed by, our general partner (or, in the case of our Canadian operations, PMC (Nova Scotia) Company). We do not pay our general partner a management fee, but we do reimburse our general partner for all expenses incurred on our behalf.

Our general partner owns the 2% general partner interest and all of the incentive distribution rights. Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, generally our general partner is entitled, without duplication, to 15% of amounts we distribute in excess of $0.450 ($1.80 annualized) per unit, 25% of the amounts we distribute in excess of $0.495 ($1.98 annualized) per unit and 50% of amounts we distribute in excess of $0.675 ($2.70 annualized) per unit.

The following table illustrates the allocation of aggregate distributions at different per-unit levels:

Annual Distribution Per Unit	Distribution to Unitholders[1][2]	Distribution to GP[1][2][3]	Total Distribution[1]	GP Percentage of Total Distribution
$ 1.80	$ 126,000	$ 2,571	$ 128,571	2.0%
$ 1.98	$ 138,600	$ 4,795	$ 143,395	3.3%
$ 2.45	$ 171,500	$ 15,762	$ 187,262	8.4%
$ 2.60	$ 182,000	$ 19,262	$ 201,262	9.6%
$ 2.80	$ 196,000	$ 28,595	$ 224,595	12.7%
$ 3.00	$ 210,000	$ 42,595	$ 252,595	16.9%

(1) In thousands.

(2) Assumes 70,000,000 units outstanding. Actual number of units outstanding as of December 31, 2004 was 67,293,108. An increase in the number of units outstanding would increase both the distribution to unitholders and the distribution to the general partner of any given level of distribution per unit.

(3) Includes distributions attributable to the 2% general partner interest and the incentive distribution rights.

Transactions with Related Parties

General

As of December 31, 2004 Vulcan Energy owned an effective 44% of our general partner interest, as well as approximately 18.3% of our outstanding limited partner units. We have ongoing relationships with Plains Resources, a wholly owned subsidiary of Vulcan Energy. These relationships include but are not limited to:

- a separation agreement entered into in 2001 in connection with the transfer of interests in our general partner pursuant to which (i) Plains Resources has indemnified us for (a) claims relating to securities laws or regulations in connection with the upstream or midstream businesses, based on alleged acts or omissions occurring on or prior to June 8, 2001, or (b) claims related to the upstream business, whenever arising, and (ii) we have indemnified Plains Resources for claims related to the midstream business, whenever arising. Plains Resources also has indemnified, and maintains liability insurance (through June 8, 2007) for the individuals who were, on or before June 8, 2001, directors or officers of Plains Resources or our former general partner.

- a Pension and Employee Benefits Assumption and Transition Services Agreement that provided for the transfer to our general partner of the employees of our former general partner and certain headquarters employees of Plains Resources.

an Omnibus Agreement that provides for the resolution of certain conflicts arising from the fact that we and Plains Resources conduct related businesses, including certain non-compete obligations of Plains Resources.

a Marketing Agreement with Plains Resources that provides for the marketing of Plains Resources' equity crude oil production (including its subsidiaries that conduct exploration and production activities.). Under the Marketing Agreement, we purchase for resale at market prices of Plains Resources equity production for a fee of $0.20 per barrel. The fee is subject to adjustment in November 2006 based on then-existing market conditions. For the year ended December 31, 2004, Plains Resources produced approximately 2,000 barrels per day that were subject to the Marketing Agreement. We paid approximately $28.3 million for such production and recognized segment profit of approximately $0.1 million under the terms of that agreement. In our opinion, these purchases were made at prevailing market prices. Because Plains Resources divested itself of most of its producing properties at the end of 2002, we do not expect material amounts of crude oil to be subject to this agreement. As currently in effect, the Marketing Agreement (as well as the Omnibus Agreement described above) will terminate upon a "change of control" of Plains Resources or our general partner. The recent purchase of Plains Resources by Vulcan Energy would have constituted a change of control under both the Marketing Agreement and the Omnibus Agreement. In July 2004, we amended and restated the Marketing Agreement and the Omnibus Agreement to except the Vulcan transaction from the change of control provisions.

Plains Resources paid $150,000 in plaintiff's attorney's fees in connection with the settlement of certain litigation in which we were a defendant.

On December 18, 2002, Plains Resources completed a spin-off of one of its subsidiaries, PXP, to its shareholders. PXP is a successor participant to the Plains Resources Marketing agreement. For the year ended December 31, 2004, PXP produced approximately 22,000 barrels per day that were subject to the Marketing Agreement. We paid approximately $328.3 million for such production and recognized segment profit of approximately $1.4 million. In our opinion, these purchases were made at prevailing market prices. We are also party to a Letter Agreement with Stocker Resources, L.P. (now PXP) that provides that if the Marketing Agreement terminates before our crude oil sales agreement with Tosco Refining Co. terminates, PXP will continue to sell and we will continue to purchase PXP's equity crude oil production from the Arroyo Grande field (now owned by a subsidiary of PXP) under the same terms as the Marketing Agreement until our Tosco sales agreement terminates. In July 2004, we amended and restated the Marketing Agreement to, among other things, reflect the change in parties as a result of the spin-off. We sell PXP's crude under sales contracts that range from one year to seven years in length. In October 2004, we further amended the PXP Marketing Agreement to exclude any newly acquired properties and to adjust the marketing fee to $0.15 per barrel for any new contracts entered into after January 1, 2005.

1998 Long-Term Incentive Plan

Our general partner maintains the 1998 LTIP for employees and directors of our general partner and its affiliates who perform services for us. The 1998 LTIP consists of two components, a restricted unit plan and a unit option plan. The 1998 LTIP permits the grant of restricted units and unit options covering delivery of an aggregate of 1,425,000 common units. No options have been granted under the plan. The plan is administered by the compensation committee of our general partner's board of directors.

A restricted unit is a "phantom" unit that entitles the grantee to receive a common unit (or cash equivalent) upon the vesting of the phantom unit. As of May 16, 2005, approximately 464,000 common units have been issued, or purchased and delivered, upon vesting and grants of approximately 59,000 phantom units remain outstanding to employees, officers and directors of our general partner. See "Management Executive Compensation."

2005 Long-Term Incentive Plan

In January 2005, our unitholders approved the 2005 LTIP. The 2005 LTIP provides for awards to our employees and directors. Awards contemplated by the 2005 LTIP include phantom units, restricted units, unit appreciation rights and unit options, as determined by the Compensation Committee (each an "Award"). Up to 3,000,000 units may be issued in satisfaction of Awards. Certain Awards may also include DERs, in the discretion of the Compensation Committee. In February 2005, our Board of Directors and Compensation Committee approved grants of approximately 1,900,000 phantom units (a substantial portion of which include DERs) under the 2005 LTIP. See "Management Executive Compensation."

Performance Option Plan

In 2001, the owners of the general partner (other than PAA Management, L.P.) contributed an aggregate of 450,000 subordinated units (now converted into common units) to the general partner to provide a pool of units available for the grant of options to management and key employees. In that regard, the general partner adopted the Plains All American 2001 Performance Option Plan, pursuant to which options to purchase units have been granted with respect to all units under the Plan. Of this amount, 75,000, 55,000, 45,000, 72,500 and 15,000 were granted to Messrs. Armstrong, Pefanis, Kramer, Coiner and Duckett, respectively, and approximately 405,000 to executive officers as a group. These options generally vest in 25% increments based upon achieving quarterly distribution levels on our units of $0.525, $0.575, $0.625 and $0.675 ($2.10, $2.30, $2.50 and $2.70, annualized). The first three levels were reached in 2002, 2004 and 2005. The options will vest in their entirety immediately upon a change in control (as defined in the grant agreements). The original purchase price under the options was $22 per subordinated unit, declining over time in an amount equal to 80% of each quarterly distribution per unit. As of May 16, 2005, the purchase price was $14.91 per unit. Because the units underlying the plan were contributed to the general partner, we will have no obligation to reimburse the general partner for the cost of the units upon exercise of the options.

Stock Option Replacement

In connection with the General Partner Transition, certain members of the management team that had been employed by Plains Resources, including Messrs. Armstrong, Pefanis and Kramer, were transferred to the general partner. At that time, such individuals held in-the-money but unvested stock options in Plains Resources, which were subject to forfeiture because of the transfer of employment. Plains Resources, through its affiliates, agreed to substitute a contingent grant of subordinated units, which are now common units pursuant to conversion, with a value equal to the spread on the unvested options, with distribution equivalent rights from the date of grant. The grant included 8,548, 4,602 and 9,742 units to Messrs. Armstrong, Pefanis and Kramer, respectively. The units vested on the same schedule as the stock options would have vested. The units granted to Messrs. Armstrong, Pefanis and Kramer vested in their entirety in 2002. The general partner administered the vesting and delivery of the units under the grants. Because the units necessary to satisfy the delivery requirements under the grants were provided by Plains Resources, we had no obligation to reimburse the general partner for the cost of such units.

CANPET Energy Group Inc.

In July 2001, we acquired the assets of CANPET Energy Group Inc., a Calgary based Canadian crude oil and LPG marketing company (the "CANPET acquisition"), for approximately $24.6 million plus excess inventory at the closing date of approximately $25.0 million. A portion of the purchase price, payable in common units or cash, at our option, was deferred subject to various performance standards being met. On April 30, 2004, we satisfied the deferred payment with the issuance of approximately 385,000 common units (representing approximately $13.1 million in value as of the date of issuance) and the payment of $6.5 million in cash. In addition, an incremental $3.7 million in cash was paid for the distributions that would have been paid on the common units had they been outstanding since the effective date of the acquisition. Mr. W. David Duckett, the President of PMC (Nova Scotia) Company, the general partner of Plains Marketing Canada, L.P., owns approximately 37.8% of CANPET, and received a proportionate share of the proceeds from the contingent payment of purchase price for the CANPET assets.

Tank Car Lease and CANPET

In connection with the CANPET acquisition, Plains Marketing Canada, L.P. assumed CANPET's rights and obligations under a Master Railcar Leasing Agreement between CANPET and Pivotal Enterprises Corporation ("Pivotal"). The agreement provides for Plains Marketing Canada, L.P. to lease approximately 57 railcars from Pivotal at a lease price of $1,000 (Canadian) per month, per car. The lease extends until June of 2008, with an option for Pivotal to extend the term of the lease for an additional five years. Pivotal is substantially owned by former employees of CANPET, including Mr. W. David Duckett. Mr. Duckett owns a 22% interest in Pivotal.

Class B Common Units

In May 1999, we sold 1,307,190 unregistered Class B common units (the "Class B common units") to our general partner at the time, Plains All American Inc., a wholly owned subsidiary of Plains Resources Inc., pursuant to Rule 4(2) of the Securities Act. We received $19.125 per Class B common unit, a price equal to the then-market value of our common units for total proceeds of approximately $25 million. We used the net proceeds from the offering to defray costs associated with our acquisition of Scurlock Permian LLC and certain other pipeline assets from Marathon Ashland Petroleum LLC. In January 2005, our common unitholders approved a change in the terms of the Class B common units such that they were immediately convertible into an equal number of common units at the option of the holders, and in February 2005, all of the Class B common units converted.

Class C Common Units

In April 2004, we sold 3,245,700 unregistered Class C common units (the "Class C common units") to a group of investors comprised of affiliates of Kayne Anderson Capital Advisors, Vulcan Capital and Tortoise Capital pursuant to Rule 4(2) under the Securities Act. For more detailed information with respect to our relationship with Kayne Anderson Capital Advisors and Vulcan Capital, see "Security Ownership of Certain Beneficial Owners and Management and Related Unitholders' Matters." We received $30.81 per Class C common unit, an amount which represented 94% of the average closing price of our common units for the twenty trading days immediately ending and including March 26, 2004. Net proceeds from the private placement, including the general partner's proportionate capital contribution and expenses associated with the sale, were approximately $101.0 million. We used the net proceeds from the offering to repay indebtedness under our revolving credit facility incurred in connection with the Link acquisition. In January 2005, our common unitholders approved a change in the terms of the Class C common units such that they were immediately convertible into an equal number of common units at the option of the holders, and in February 2005, all of the Class C common units converted.

Other

An affiliate of Kayne Anderson Investment Management, Inc. participated in our December 2003 and July 2004 equity offerings. In the aggregate for both offerings, it earned approximately $672,000 in commissions for its participation.

DESCRIPTION OF OUR COMMON UNITS

Generally, our common units represent limited partner interests that entitle the holders to participate in our cash distributions and to exercise the rights and privileges available to limited partners under our partnership agreement. For a description of the relative rights and preferences of holders of common units and our general partner in and to cash distributions. See "Cash Distribution Policy."

Our outstanding common units are listed on the NYSE under the symbol "PAA." Any additional common units we issue will also be listed on the NYSE.

The transfer agent and registrar for our common units is American Stock Transfer & Trust Company.

Meetings/Voting

Each holder of common units is entitled to one vote for each common unit on all matters submitted to a vote of the unitholders.

Status as Limited Partner or Assignee

Except as described below under " Limited Liability," the common units will be fully paid, and unitholders will not be required to make additional capital contributions to us.

Each purchaser of common units offered by this prospectus must execute a transfer application whereby the purchaser requests admission as a substituted limited partner and makes representations and agrees to provisions stated in the transfer application. If this action is not taken, a purchaser will not be registered as a record holder of common units on the books of our transfer agent or issued a common unit certificate. Purchasers may hold common units in nominee accounts.

An assignee, pending its admission as a substituted limited partner, is entitled to an interest in us equivalent to that of a limited partner with respect to the right to share in allocations and distributions, including liquidating distributions. Our general partner will vote and exercise other powers attributable to common units owned by an assignee who has not become a substituted limited partner at the written direction of the assignee. Transferees who do not execute and deliver transfer applications will be treated neither as assignees nor as record holders of common units and will not receive distributions, federal income tax allocations or reports furnished to record holders of common units. The only right the transferees will have is the right to admission as a substituted limited partner in respect of the transferred common units upon execution of a transfer application in respect of the common units. A nominee or broker who has executed a transfer application with respect to common units held in street name or nominee accounts will receive distributions and reports pertaining to its common units.

Limited Liability

Assuming that a limited partner does not participate in the control of our business within the meaning of the Delaware Revised Uniform Limited Partnership Act (the "Delaware Act") and that he otherwise acts in conformity with the provisions of our partnership agreement, his liability under the Delaware Act will be limited, subject to some possible exceptions, generally to the amount of capital he is obligated to contribute to us in respect of his units plus his share of any undistributed profits and assets.

Under the Delaware Act, a limited partnership may not make a distribution to a partner to the extent that at the time of the distribution, after giving effect to the distribution, all liabilities of the partnership, other than liabilities to partners on account of their partnership interests and liabilities for which the recourse of creditors is limited to specific property of the partnership, exceed the fair value of the assets of the limited partnership. For the purposes of determining the fair value of the assets of a limited partnership, the Delaware Act provides that the fair value of the property subject to liability of which recourse of creditors is limited shall be included in the assets of the limited partnership only to the extent that the fair value of that property exceeds the nonrecourse liability. The Delaware Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of the Delaware Act is liable to the limited partnership for the amount of the distribution for three years from the date of the distribution.

Reports and Records

As soon as practicable, but in no event later than 120 days after the close of each fiscal year, our general partner will furnish or make available to each unitholder of record (as of a record date selected by our general partner) an annual report containing our audited financial statements for the past fiscal year. These financial statements will be prepared in accordance with generally accepted accounting principles. In addition, no later than 45 days after the close of each quarter (except the fourth quarter), our general partner will furnish or make available to each unitholder of record (as of a record date selected by our general partner) a report containing our unaudited financial statements and any other information required by law.

Our general partner will use all reasonable efforts to furnish each unitholder of record information reasonably required for tax reporting purposes within 90 days after the close of each fiscal year. Our general partner's ability to furnish this summary tax information will depend on the cooperation of unitholders in supplying information to our general partner. Each unitholder will receive information to assist him in determining his U.S. federal and state and Canadian federal and provincial tax liability and filing his U.S. federal and state and Canadian federal and provincial income tax returns.

A limited partner can, for a purpose reasonably related to the limited partner's interest as a limited partner, upon reasonable demand and at his own expense, have furnished to him:

- a current list of the name and last known address of each partner;
- a copy of our tax returns;
- information as to the amount of cash and a description and statement of the agreed value of any other property or services, contributed or to be contributed by each partner and the date on which each became a partner;
- copies of our partnership agreement, our certificate of limited partnership, amendments to either of them and powers of attorney which have been executed under our partnership agreement;
- information regarding the status of our business and financial condition; and
- any other information regarding our affairs as is just and reasonable.

Our general partner may, and intends to, keep confidential from the limited partners trade secrets and other information the disclosure of which our general partner believes in good faith is not in our best interest or which we are required by law or by agreements with third parties to keep confidential.

Class B Common Units

In connection with our acquisition of Scurlock Permian LLC, in May 1999, we issued 1,307,190 Class B common units for $19.125 per unit in a private placement to our general partner at the time, Plains All American Inc. The Class B common units generally had voting rights that were identical to the voting rights of the common units and voted with the common units as a single class on each matter, except that the Class B common units were not entitled to vote upon the NYSE listing

proposals relating to the conversion of the Class B common units or Class C common units into common units. Each Class B common unit was entitled to receive 100% of the quarterly amount distributed on each common unit for each quarter. In January 2005, our common unitholders approved a change in the terms of the Class B Common units such that they were immediately convertible into an equal number of Common Units at the option of the holders, and in February 2005, all of the Class B common units converted.

Class C Common Units

In connection with the Link acquisition, on April 15, 2004, we issued 3,245,700 Class C common units for $30.81 per unit in a private placement to a group of institutional investors comprised of affiliates of Kayne Anderson Capital Advisors, Vulcan Capital and Tortoise Capital Advisors. The Class C common units generally had voting rights that were identical to the voting rights of the common units and voted with the common units as a single class on each matter, except that the Class C common units were not entitled to vote upon the NYSE listing proposals relating to the conversion of the Class B common units or Class C common units into common units. Each Class C common unit was entitled to receive 100% of the quarterly amount distributed on each common unit for each quarter. In January 2005, our common unitholders approved a change in the terms of the Class C Common units such that they were immediately convertible into an equal number of Common Units at the option of the holders, and in February 2005, all of the Class C common units converted.

CASH DISTRIBUTION POLICY

Distributions of Available Cash

General. We will distribute to our unitholders, on a quarterly basis, all of our available cash in the manner described below.

Definition of Available Cash. Available cash generally means, for any quarter ending prior to liquidation, all cash on hand at the end of that quarter less the amount of cash reserves that are necessary or appropriate in the reasonable discretion of the general partner to:

- provide for the proper conduct of our business;
- comply with applicable law or any partnership debt instrument or other agreement; or
- provide funds for distributions to unitholders and the general partner in respect of any one or more of the next four quarters.

Operating Surplus and Capital Surplus

General. Cash distributions to our unitholders will be characterized as either operating surplus or capital surplus. We distribute available cash from operating surplus differently than available cash from capital surplus. See " Quarterly Distributions of Available Cash."

Definition of Operating Surplus. Operating surplus refers generally to:

- our cash balances on the closing date of this offering; plus
- $25 million; plus
- all of our cash receipts from operations, excluding cash that is capital surplus; less
- all of our operating expenses, debt service payments, including reserves but not including payments required with the sale of assets or any refinancing with the proceeds of new indebtedness or an equity offering, maintenance capital expenditures and reserves established for future operations.

Definition of Capital Surplus. Capital surplus will generally be generated only by:

- borrowings other than working capital borrowings;
- sales of debt and equity securities; and
- sales or other dispositions of assets for cash, other than inventory, accounts receivable and other assets in the ordinary course of business.

We will treat all available cash distributed as coming from operating surplus until the sum of all available cash distributed since we began equals the operating surplus as of the end of the quarter prior to the distribution. Any available cash in excess of operating surplus, regardless of its source, will be treated as capital surplus.

If we distribute available cash from capital surplus for each common unit in an aggregate amount per common unit equal to the initial public offering price of the common units, there will not be a distinction between operating surplus and capital surplus, and all distributions of available cash will be treated as operating surplus. We do not anticipate that we will make distributions from capital surplus.

Incentive Distribution Rights

The incentive distribution rights represent the right to receive an increasing percentage of quarterly distributions of available cash from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. The target distribution levels are based on the amounts of available cash from operating surplus distributed above the payments made under the minimum quarterly distribution, if any, and the related 2% distribution to the general partner.

Effect of Issuance of Additional Units

We can issue additional common units or other equity securities for consideration and under terms and conditions approved by our general partner in its sole discretion and without the approval of our unitholders. We may fund acquisitions through the issuance of additional common units or other equity securities.

Holders of any additional common units that we issue will be entitled to share equally with our then-existing unitholders in distributions of available cash. In addition, the issuance of additional interests may dilute the value of the interests of the then-existing unitholders. If we issue additional partnership interests, our general partner will be required to make an additional capital contribution to us or the operating partnership.

Quarterly Distributions of Available Cash

We will make quarterly distributions to our partners prior to our liquidation in an amount equal to 100% of our available cash for that quarter. We expect to make distributions of all available cash within approximately 45 days after the end of each quarter to holders of record on the applicable record date. The minimum quarterly distribution and the target distribution levels are also subject to certain other adjustments as described below under " Distributions from Capital Surplus" and " Adjustment to the Minimum Quarterly Distribution and Target Distribution Levels."

Distributions From Operating Surplus

We will make distributions of available cash from operating surplus in the following manner:

First, 98% to all unitholders, pro rata, and 2% to the general partner, until we distribute for each unit an amount equal to the minimum quarterly distribution for that quarter; and

Thereafter, in the manner described in " Incentive Distributions" below.

Incentive Distribution Rights

For any quarter that we distribute available cash from operating surplus to the common unitholders in an amount equal to the minimum quarterly distribution on all units, then we will distribute any additional available cash from operating surplus in that quarter among the unitholders and the general partner in the following manner:

First, 85% to all unitholders, pro rata, and 15% to the general partner, until each unitholder receives a total of $0.495 for that quarter for each outstanding unit (the "first target distribution");

Second, 75% to all unitholders, pro rata, and 25% to the general partner, until each unitholder receives a total of $0.675 for that quarter for each outstanding unit (the "second target distribution"); and

Thereafter, 50% to all unitholders, pro rata, and 50% to the general partner.

Our distributions to the general partner above, other than in its capacity as holders of units, that are in excess of its aggregate 2% general partner interest represent the incentive distribution rights. The right to receive incentive distribution rights is not part of its general partner interest and may be transferred separately from that interest, subject to certain restrictions.

Distributions from Capital Surplus

How Distributions from Capital Surplus Will Be Made. We will make distributions of available cash from capital surplus in the following manner:

- First, 98% to all unitholders, pro rata, and 2% to the general partner, until we distribute, for each common unit issued in this offering, available cash from capital surplus in an aggregate amount per common unit equal to the initial public offering price; and

- Thereafter, we will make all distributions of available cash from capital surplus as if they were from operating surplus.

Effect of a Distribution from Capital Surplus. Our partnership agreement treats a distribution of available cash from capital surplus as the repayment of the initial unit price. To show that repayment, the minimum quarterly distribution and the target distribution levels will be reduced by multiplying each amount by a fraction, the numerator of which is the unrecovered capital of the common units immediately after giving effect to that repayment and the denominator of which is the unrecovered capital of the common units immediately prior to that repayment.

When Payback Occurs. When "payback" of the reduced initial unit price has occurred, i.e., when the unrecovered capital of the common units is zero, and then

- the minimum quarterly distribution and the target distribution levels will be reduced to zero for subsequent quarters;

- all distributions of available cash will be treated as operating surplus; and

- the general partner will be entitled to receive 50% of distributions of available cash in its capacities as general partner and as holder of the incentive distribution rights.

Distributions of available cash from capital surplus will not reduce the minimum quarterly distribution or target distribution levels for the quarter in which they are distributed.

Adjustment to the Minimum Quarterly Distribution and Target Distribution Levels

How We Adjust the Minimum Quarterly Distribution and Target Distribution Levels. In addition to adjusting the minimum quarterly distribution and target distribution levels to reflect a distribution of capital surplus, if we combine our units into fewer units or subdivide our units into a greater number of units (but not if we issue additional common units for cash or property), we will proportionately adjust:

- the minimum quarterly distribution;

- the target distribution levels;

- the unrecovered capital; and

- other amounts calculated on a per unit basis.

For example, in the event of a two-for-one split of the common units (assuming no prior adjustments), the minimum quarterly distribution, each of the target distribution levels and the unrecovered capital of the common units would each be reduced to 50% of its initial level.

If We Became Subject to Taxation. If legislation is enacted or if existing law is modified or interpreted by the relevant governmental authority so that we become taxable as a corporation or otherwise subject to taxation as an entity for federal, state or local income tax purposes, we will reduce

the minimum quarterly distribution and each of the target distribution levels, respectively, multiplied by:

one minus the sum of (x) the maximum effective federal income tax rate to which we as an entity were subject plus (y) any increase in state and local income taxes to which we are subject for the taxable year of the event, after adjusting for any allowable deductions for federal income tax purposes for the payment of state and local income taxes.

For example, assuming we were not previously subject to state and local income tax, if we become taxable as an entity for federal income tax purposes and became subject to a maximum marginal federal, and effective state and local, income tax rate of 38%, then the minimum quarterly distribution and the target distribution levels would each be reduced to 62% of the amount immediately prior to that adjustment.

Distribution of Cash Upon Liquidation

General. If we dissolve and liquidate, we will sell our assets or otherwise dispose of our assets and we will adjust the partners' capital account balances to show any resulting gain or loss. We will first apply the proceeds of liquidation to the payment of our creditors in the order of priority provided in our partnership agreement and by law and, thereafter, distribute to the unitholders and the general partner in accordance with their adjusted capital account balances.

Manner of Adjustment. If we liquidate, we would allocate any loss to the general partner and each unitholder as follows:

First, 98% to the holders of common units who have positive balances in their capital accounts in proportion to those positive balances and 2% to the general partner, until the capital accounts of the common unitholders have been reduced to zero; and

Thereafter, 100% to the general partner.

Interim Adjustments to Capital Accounts. If we issued additional security interests or made distributions of property, interim adjustments to capital accounts would also be made. These adjustments would be based on the fair market value of the interests or the property distributed and any gain or loss would be allocated to the unitholders and the general partner in the same way that a gain or loss is allocated upon liquidation. If positive interim adjustments are made to the capital accounts, any subsequent negative adjustments to the capital accounts resulting from our issuance of additional interests, distributions of property, or upon our liquidation, would be allocated in a way that, to the extent possible, in the capital account balances of the general partner equaling the amount which would have been the general partner's capital account balances if no prior positive adjustments to the capital accounts had been made.

DESCRIPTION OF OUR PARTNERSHIP AGREEMENT

The following is a summary of the material provisions of our partnership agreement. The following provisions of our partnership agreement are summarized elsewhere in this prospectus:

- distributions of our available cash are described under "Cash Distribution Policy";
- allocations of taxable income and other tax matters are described under "Tax Considerations"; and
- rights of holders of common units are described under "Description of Our Common Units."

Purpose

Our purpose under our partnership agreement is to serve as a partner of our operating partnerships and to engage in any business activities that may be engaged in by our operating partnerships or that is approved by our general partner. The partnership agreements of our operating partnerships provide that they may engage in any activity that was engaged in by our predecessors at the time of our initial public offering or reasonably related thereto and any other activity approved by our general partner.

Power of Attorney

Each limited partner, and each person who acquires a unit from a unitholder and executes and delivers a transfer application, grants to our general partner and, if appointed, a liquidator, a power of attorney to, among other things, execute and file documents required for our qualification, continuance or dissolution. The power of attorney also grants the authority for the amendment of, and to make consents and waivers under, our partnership agreement.

Reimbursements of Our General Partner

Our general partner does not receive any compensation for its services as our general partner. It is, however, entitled to be reimbursed for all of its costs incurred in managing and operating our business. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion.

Issuance of Additional Securities

Our partnership agreement authorizes us to issue an unlimited number of additional limited partner interests and other equity securities that are equal in rank with or junior to our common units on terms and conditions established by our general partner in its sole discretion without the approval of any limited partners.

It is likely that we will fund acquisitions through the issuance of additional common units or other equity securities. Holders of any additional common units we issue will be entitled to share equally with the then-existing holders of common units in our cash distributions. In addition, the issuance of additional partnership interests may dilute the value of the interests of the then-existing holders of common units in our net assets.

In accordance with Delaware law and the provisions of our partnership agreement, we may also issue additional partnership interests that, in the sole discretion of our general partner, may have special voting rights to which common units are not entitled.

Our general partner has the right, which it may from time to time assign in whole or in part to any of its affiliates, to purchase common units or other equity securities whenever, and on the same terms that, we issue those securities to persons other than our general partner and its affiliates, to the extent necessary to maintain their percentage interests in us that existed immediately prior to the issuance. The holders of common units will not have preemptive rights to acquire additional common units or other partnership interests in us.

Amendments to Our Partnership Agreement

Amendments to our partnership agreement may be proposed only by our general partner. Any amendment that materially and adversely affects the rights or preferences of any type or class of limited partner interests in relation to other types or classes of limited partner interests or our general partner interest will require the approval of at least a majority of the type or class of limited partner interests or general partner interests so affected. However, in some circumstances, more particularly described in our partnership agreement, our general partner may make amendments to our partnership agreement without the approval of our limited partners or assignees.

Withdrawal or Removal of Our General Partner

Our general partner has agreed not to withdraw voluntarily as our general partner prior to December 31, 2008 without obtaining the approval of the holders of a majority of our outstanding common units, excluding those held by our general partner and its affiliates, and furnishing an opinion of counsel regarding limited liability and tax matters. On or after December 31, 2008, our general partner may withdraw as general partner without first obtaining approval of any unitholder by giving 90 days' written notice, and that withdrawal will not constitute a violation of our partnership agreement. In addition, our general partner may withdraw without unitholder approval upon 90 days' notice to our limited partners if at least 50% of our outstanding common units are held or controlled by one person and its affiliates other than our general partner and its affiliates.

Upon the voluntary withdrawal of our general partner, the holders of a majority of our outstanding common units, excluding the common units held by the withdrawing general partner and its affiliates, may elect a successor to the withdrawing general partner. If a successor is not elected, or is elected but an opinion of counsel regarding limited liability and tax matters cannot be obtained, we will be dissolved, wound up and liquidated, unless within 90 days after that withdrawal, the holders of a majority of our outstanding units, excluding the common units held by the withdrawing general partner and its affiliates agree to continue our business and to appoint a successor general partner.

Our general partner may not be removed unless that removal is approved by the vote of the holders of not less than two-thirds of our outstanding units, including units held by our general partner and its affiliates, and we receive an opinion of counsel regarding limited liability and tax matters. Any removal of this kind is also subject to the approval of a successor general partner by the vote of the holders of a majority of our outstanding common units, including those held by our general partner and its affiliates.

While our partnership agreement limits the ability of our general partner to withdraw, it allows the general partner interest and incentive distribution rights to be transferred to an affiliate or to a third party in conjunction with a merger or sale of all or substantially all of the assets of our general partner.

In addition, our partnership agreement expressly permits the sale, in whole or in part, of the ownership of our general partner. Our general partner may also transfer, in whole or in part, the common units it owns.

Liquidation and Distribution of Proceeds

Upon our dissolution, unless we are reconstituted and continued as a new limited partnership, the person authorized to wind up our affairs (the liquidator) will, acting with all the powers of our general partner that the liquidator deems necessary or desirable in its good faith judgment, liquidate our assets. The proceeds of the liquidation will be applied as follows:

- first, towards the payment of all of our creditors and the creation of a reserve for contingent liabilities; and
- then, to all partners in accordance with the positive balance in the respective capital accounts.

Under some circumstances and subject to some limitations, the liquidator may defer liquidation or distribution of our assets for a reasonable period of time. If the liquidator determines that a sale would be impractical or would cause a loss to our partners, our general partner may distribute assets in kind to our partners.

Change of Management Provisions

Our partnership agreement contains the following specific provisions that are intended to discourage a person or group from attempting to remove our general partner or otherwise change management:

- generally, if a person acquires 20% or more of any class of units then outstanding other than from our general partner or its affiliates, the units owned by such person cannot be voted on any matter; and

- provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

Limited Call Right

If at any time our general partner and its affiliates own 80% or more of the issued and outstanding limited partner interests of any class, our general partner will have the right to purchase all, but not less than all, of the outstanding limited partner interests of that class that are held by non-affiliated persons. The record date for determining ownership of the limited partner interests would be selected by our general partner on at least 10 but not more than 60 days' notice. The purchase price in the event of a purchase under these provisions would be the greater of (1) the current market price (as defined in our agreement) of the limited partner interests of the class as of the date three days prior to the date that notice is mailed to the limited partners as provided in our partnership agreement and (2) the highest cash price paid by our general partner or any of its affiliates for any limited partner interest of the class purchased within the 90 days preceding the date our general partner mails notice of its election to purchase the units.

Indemnification

Under our partnership agreement, in most circumstances, we will indemnify our general partner, its affiliates and their officers and directors to the fullest extent permitted by law, from and against all losses, claims or damages any of them may suffer by reason of their status as general partner, officer or director, as long as the person seeking indemnity acted in good faith and in a manner believed to be in or not opposed to our best interest. Any indemnification under these provisions will only be out of our assets. Our general partner shall not be personally liable for, or have any obligation to contribute or loan funds or assets to us to enable us to effectuate any indemnification. We are authorized to purchase insurance against liabilities asserted against and expenses incurred by persons for our activities, regardless of whether we would have the power to indemnify the person against liabilities under our partnership agreement.

Registration Rights

Under our partnership agreement, we have agreed to register for resale under the Securities Act and applicable state securities laws any common units, or other partnership securities proposed to be sold by our general partner or any of its affiliates or their assignees if an exemption from the registration requirements is not otherwise available. We are obligated to pay all expenses incidental to the registration, excluding underwriting discounts and commissions.

TAX CONSIDERATIONS

This section is a summary of the material tax considerations that may be relevant to prospective unitholders who are individual citizens or residents of the United States and, unless otherwise noted in the following discussion, expresses the opinion of Vinson & Elkins L.L.P., counsel to the general partner and us, insofar as it relates to matters of United States federal income tax law and legal conclusions with respect to those matters.

This section is based upon current provisions of the Internal Revenue Code, existing and proposed regulations and current administrative rulings and court decisions, all of which are subject to change. Later changes in these authorities may cause the tax consequences to vary substantially from the consequences described below.

No attempt has been made in the following discussion to comment on all federal income tax matters affecting us or our unitholders. Moreover, the discussion focuses on unitholders who are individual citizens or residents of the United States and has only limited application to corporations, estates, trusts, nonresident aliens or other unitholders subject to specialized tax treatment, such as tax-exempt institutions, foreign persons, individual retirement accounts (IRAs), real estate investment trusts (REITs) or mutual funds. Accordingly, we recommend that each prospective unitholder consult, and depend on, his own tax advisor in analyzing the federal, state, local and foreign tax consequences particular to him of the ownership or disposition of common units.

All statements as to matters of law and legal conclusions, but not as to factual matters, contained in this section, unless otherwise noted, are the opinion of counsel and are based on the accuracy of the factual representations made by us.

No ruling has been or will be requested from the IRS regarding any matter affecting us or prospective unitholders. An opinion of counsel represents only that counsel's best legal judgment and does not bind the IRS or the courts. Accordingly, the opinions and statements made here may not be sustained by a court if contested by the IRS. Any contest of this sort with the IRS may materially and adversely impact the market for the common units and the prices at which common units trade. In addition, the costs of any contest with the IRS will be borne directly or indirectly by the unitholders and the general partner. Furthermore, the treatment of us, or an investment in us, may be significantly modified by future legislative or administrative changes or court decisions. Any modifications may or may not be retroactively applied.

For the reasons described below, counsel has not rendered an opinion with respect to the following specific federal income tax issues:

(1) the treatment of a unitholder whose common units are loaned to a short seller to cover a short sale of common units (please read " Tax Consequences of Unit Ownership Treatment of Short Sales");

(2) whether our monthly convention for allocating taxable income and losses is permitted by existing Treasury Regulations (please read " Disposition of Common Units Allocations Between Transferors and Transferees"); and

(3) whether our method for depreciating Section 743 adjustments is sustainable (please read " Tax Consequences of Unit Ownership Section 754 Election").

Partnership Status

A partnership is not a taxable entity and incurs no federal income tax liability. Instead, each partner of a partnership is required to take into account his share of items of income, gain, loss and deduction of the partnership in computing his federal income tax liability, regardless of whether cash distributions are made to him by the partnership. Distributions by a partnership to a partner are generally not taxable unless the amount of cash distributed is in excess of the partner's adjusted basis in his partnership interest.

No ruling has been or will be sought from the IRS and the IRS has made no determination as to our status or the status of the operating partnerships as partnerships for federal income tax purposes or whether our operations generate "qualifying income" under Section 7704 of the Code. Instead, we will rely on the opinion of counsel that, based upon the Internal Revenue Code, its regulations, published revenue rulings and court decisions and the representations described below, we and the operating partnerships will be classified as a partnership for federal income tax purposes.

In rendering its opinion, counsel has relied on factual representations made by us and the general partner. The representations made by us and our general partner upon which counsel has relied are:

(a) neither we nor the operating partnerships will elect to be treated as a corporation;

(b) for each taxable year, more than 90% of our gross income will be income from sources that our counsel has opined or will opine is "qualifying income" within the meaning of Section 7704(d) of the Internal Revenue Code.

Section 7704 of the Internal Revenue Code provides that publicly-traded partnerships will, as a general rule, be taxed as corporations. However, an exception, referred to as the "Qualifying Income Exception," exists with respect to publicly-traded partnerships of which 90% or more of the gross income for every taxable year consists of "qualifying income." Qualifying income includes income and gains derived from the transportation and marketing of crude oil, natural gas and products thereof. Other types of qualifying income include interest (other than from a financial business), dividends, gains from the sale of real property and gains from the sale or other disposition of assets held for the production of income that otherwise constitutes qualifying income. We estimate that less than 3% of our current income is not qualifying income; however, this estimate could change from time to time. Based upon and subject to this estimate, the factual representations made by us and the general partner and a review of the applicable legal authorities, counsel is of the opinion that at least 90% of our current gross income constitutes qualifying income.

If we fail to meet the Qualifying Income Exception, other than a failure which is determined by the IRS to be inadvertent and that is cured within a reasonable time after discovery, we will be treated as if we had transferred all of our assets, subject to liabilities, to a newly formed corporation, on the first day of the year in which we fail to meet the Qualifying Income Exception, in return for stock in that corporation, and then distributed that stock to the unitholders in liquidation of their interests in us. This contribution and liquidation should be tax-free to unitholders and us so long as we, at that time, do not have liabilities in excess of the tax basis of our assets. Thereafter, we would be treated as a corporation for federal income tax purposes.

If we were taxable as a corporation in any taxable year, either as a result of a failure to meet the Qualifying Income Exception or otherwise, our items of income, gain, loss and deduction would be reflected only on our tax return rather than being passed through to our unitholders, and our net income would be taxed to us at corporate rates. In addition, any distribution made to a unitholder would be treated as either taxable dividend income, to the extent of our current or accumulated earnings and profits, or, in the absence of earnings and profits, a nontaxable return of capital, to the extent of the unitholder's tax basis in his common units, or taxable capital gain, after the unitholder's tax basis in his common units has been reduced to zero. Accordingly, taxation as a corporation would result in a material reduction in a unitholder's cash flow and after-tax return and thus would likely result in a substantial reduction of the value of the units.

The discussion below is based on the conclusion that we will be classified as a partnership for federal income tax purposes.

Limited Partner Status

Unitholders who have become limited partners of Plains All American Pipeline will be treated as partners of Plains All American Pipeline for federal income tax purposes. Also:

- assignees who have executed and delivered transfer applications, and are awaiting admission as limited partners and

- unitholders whose common units are held in street name or by a nominee and who have the right to direct the nominee in the exercise of all substantive rights attendant to the ownership of their common units,

will be treated as partners of Plains All American Pipeline for federal income tax purposes. As there is no direct authority addressing assignees of common units who are entitled to execute and deliver transfer applications and become entitled to direct the exercise of attendant rights, but who fail to execute and deliver transfer applications, counsel's opinion does not extend to these persons. Furthermore, a purchaser or other transferee of common units who does not execute and deliver a transfer application may not receive some federal income tax information or reports furnished to record holders of common units unless the common units are held in a nominee or street name account and the nominee or broker has executed and delivered a transfer application for those common units.

A beneficial owner of common units whose units have been transferred to a short seller to complete a short sale would appear to lose his status as a partner with respect to those units for federal income tax purposes. Please read " Tax Consequences of Unit Ownership Treatment of Short Sales."

Income, gain, deductions or losses would not appear to be reportable by a unitholder who is not a partner for federal income tax purposes, and any cash distributions received by a unitholder who is not a partner for federal income tax purposes would therefore be fully taxable as ordinary income. These holders should consult their own tax advisors with respect to their status as partners in Plains All American Pipeline for federal income tax purposes.

Tax Consequences of Unit Ownership

Flow-through of Taxable Income. We will not pay any federal income tax. Instead, each unitholder will be required to report on his income tax return his share of our income, gains, losses and deductions without regard to whether corresponding cash distributions are received by that unitholder. Consequently, we may allocate income to a unitholder even if he has not received a cash distribution. Each unitholder will be required to include in income his share of our income, gains, losses and deductions for our taxable year ending with or within his taxable year.

Treatment of Distributions. Distributions by us to a unitholder generally will not be taxable to the unitholder for federal income tax purposes to the extent of his tax basis in his common units immediately before the distribution. Our cash distributions in excess of a unitholder's tax basis generally will be considered to be gain from the sale or exchange of the common units, taxable in accordance with the rules described under " Disposition of Common Units" below. Any reduction in a unitholder's share of our liabilities for which no partner, including the general partner, bears the economic risk of loss, known as "nonrecourse liabilities," will be treated as a distribution of cash to that unitholder. To the extent our distributions cause a unitholder's "at risk" amount to be less than zero at the end of any taxable year, he must recapture any losses deducted in previous years. Please read " Limitations on Deductibility of Losses."

A decrease in a unitholder's percentage interest in us because of our issuance of additional common units will decrease his share of our nonrecourse liabilities, and thus will result in a corresponding deemed distribution of cash. A non-pro rata distribution of money or property may result in ordinary income to a unitholder, regardless of his tax basis in his common units, if the distribution reduces the unitholder's share of our "unrealized receivables," including depreciation recapture, and/or substantially appreciated "inventory items," both as defined in Section 751 of the Internal Revenue Code, and collectively, "Section 751 Assets." To that extent, he will be treated as having been distributed his proportionate share of the Section 751 Assets and having exchanged those assets with us in return for the non-pro rata portion of the actual distribution made to him. This latter deemed exchange will generally result in the unitholder's realization of ordinary income. That income will equal the excess of (1) the non-pro rata portion of that distribution over (2) the unitholder's tax basis for the share of Section 751 Assets deemed relinquished in the exchange.

Basis of Common Units. A unitholder's initial tax basis for his common units will be the amount he paid for the common units plus his share of our nonrecourse liabilities. That basis will be increased by his share of our income and by any increases in his share of our nonrecourse liabilities. That basis will be decreased, but not below zero, by distributions from us, by the unitholder's share of our losses, by any decreases in his share of our nonrecourse liabilities and by his share of our expenditures that are not deductible in computing taxable income and are not required to be capitalized. A limited partner will have no share of our debt which is recourse to the general partner, but will have a share, generally based on his share of profits, of our nonrecourse liabilities. Please read " Disposition of Common Units Recognition of Gain or Loss."

Limitations on Deductibility of Losses. The deduction by a unitholder of his share of our losses will be limited to the tax basis in his units and, in the case of an individual unitholder or a corporate unitholder, if more than 50% of the value of its stock is owned directly or indirectly by five or fewer individuals or some tax-exempt organizations, to the amount for which the unitholder is considered to be "at risk" with respect to our activities, if that is less than his tax basis. A unitholder must recapture losses deducted in previous years to the extent that distributions cause his at risk amount to be less than zero at the end of any taxable year. Losses disallowed to a unitholder or recaptured as a result of these limitations will carry forward and will be allowable to the extent that his tax basis or at risk amount, whichever is the limiting factor, is subsequently increased. Upon the taxable disposition of a unit, any gain recognized by a unitholder can be offset by losses that were previously suspended by the at risk limitation but may not be offset by losses suspended by the basis limitation. Any excess loss above that gain previously suspended by the at risk or basis limitations will no longer utilizable.

In general, a unitholder will be at risk to the extent of the tax basis of his units, excluding any portion of that basis attributable to his share of our nonrecourse liabilities, reduced by any amount of money he borrows to acquire or hold his units, if the lender of those borrowed funds owns an interest in us, is related to the unitholder or can look only to the units for repayment. A unitholder's at risk amount will increase or decrease as the tax basis of the unitholder's units increases or decreases, other than tax basis increases or decreases attributable to increases or decreases in his share of our nonrecourse liabilities.

The passive loss limitations generally provide that individuals, estates, trusts and some closely-held corporations and personal service corporations can deduct losses from passive activities, which are generally activities in which the taxpayer does not materially participate, only to the extent of the taxpayer's income from those passive activities. The passive loss limitations are applied separately with respect to each publicly-traded partnership. Consequently, any passive losses we generate will only be available to offset our passive income generated in the future and will not be available to offset income from other passive activities or investments, including our investments or investments in other publicly-traded partnerships, or salary or active business income. Passive losses that are not deductible because they exceed a unitholder's share of income we generate may be deducted in full when he disposes of his entire investment in us in a fully taxable transaction with an unrelated party. The passive activity loss rules are applied after other applicable limitations on deductions, including the at risk rules and the basis limitation.

A unitholder's share of our net income may be offset by any suspended passive losses, but it may not be offset by any other current or carryover losses from other passive activities, including those attributable to other publicly-traded partnerships.

Limitations on Interest Deductions. The deductibility of a non-corporate taxpayer's "investment interest expense" is generally limited to the amount of that taxpayer's "net investment income." Investment interest expense includes:

- interest on indebtedness properly allocable to property held for investment;
- our interest expense attributed to portfolio income; and
- the portion of interest expense incurred to purchase or carry an interest in a passive activity to the extent attributable to portfolio income.

The computation of a unitholder's investment interest expense will take into account interest on any margin account borrowing or other loan incurred to purchase or carry a unit. Net investment income includes gross income from property held for investment and amounts treated as portfolio income under the passive loss rules, less deductible expenses, other than interest, directly connected with the production of investment income, but generally does not include gains attributable to the disposition of property held for investment. The IRS has indicated that net passive income from a publicly-traded partnership will be treated as investment income for purposes of the limitations on the deductibility of investment interest. In addition, the unitholder's share of our portfolio income will be treated as investment income.

Entity-Level Collections. If we are required or elect under applicable law to pay any federal, state or local income tax on behalf of any unitholder or the general partner or any former unitholder, we are authorized to pay those taxes from our funds. That payment, if made, will be treated as a distribution of cash to the partner on whose behalf the payment was made. If the payment is made on behalf of a person whose identity cannot be determined, we are authorized to treat the payment as a distribution to all current unitholders. We are authorized to amend our partnership agreement in the manner necessary to maintain uniformity of intrinsic tax characteristics of units and to adjust later distributions, so that after giving effect to these distributions, the priority and characterization of distributions otherwise applicable under our partnership agreement is maintained as nearly as is practicable. Payments by us as described above could give rise to an overpayment of tax on behalf of an individual partner in which event the partner would be required to file a claim in order to obtain a credit or refund.

Allocation of Income, Gain, Loss and Deduction. In general, if we have a net profit, our items of income, gain, loss and deduction will be allocated among the general partner and the unitholders in accordance with their percentage interests in us. At any time that incentive distributions are made to the general partner, gross income will be allocated to the recipients to the extent of these distributions. If we have a net loss for the entire year, that loss will be allocated first to the general partner and the unitholders in accordance with their percentage interests in us to the extent of their positive capital accounts and, second, to the general partner.

Specified items of our income, gain, loss and deduction will be allocated to account for the difference between the tax basis and fair market value of property contributed to us by the general partner, referred to in this discussion as "Contributed Property," and to account for the difference between the fair market value of our assets and their carrying value on our books at the time of an offering. The effect of these allocations to a unitholder purchasing common units in an offering will be essentially the same as if the tax basis of our assets were equal to their fair market value at the time of the offering. In addition, items of recapture income will be allocated to the extent possible to the partner who was allocated the deduction giving rise to the treatment of that gain as recapture income in order to minimize the recognition of ordinary income by some unitholders. Finally, although we do not expect that our operations will result in the creation of negative capital accounts, if negative capital accounts nevertheless result, items of our income and gain will be allocated in an amount and manner to eliminate the negative balance as quickly as possible.

An allocation of items of our income, gain, loss or deduction, other than an allocation required by the Internal Revenue Code to eliminate the difference between a partner's "book" capital account, credited with the fair market value of Contributed Property, and "tax" capital account, credited with the tax basis of Contributed Property referred to in this discussion as the "Book-Tax Disparity", will generally be given effect for federal income tax purposes in determining a partner's share of an item of income, gain, loss or deduction only if the allocation has substantial economic effect. In any other case, a partner's share of an item will be determined on the basis of the partner's interest in us, which will be determined by taking into account all the facts and circumstances, including the partner's relative contributions to us, the interests of all the partners in profits and losses, the interest of all the partners in cash flow and other nonliquidating distributions and rights of the partners to distributions of capital upon liquidation.

Counsel is of the opinion that, with the exception of the issues described in " Tax Consequences of Unit Ownership Section 754 Election" and " Disposition of Common Units Allocations Between Transferors and Transferees," respectively, allocations under our partnership agreement will be given effect for federal income tax purposes in determining a partner's share of an item of income, gain, loss or deduction.

Treatment of Short Sales. A unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of those units. If so, he would no longer be a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition. As a result, during this period:

- any of our income, gain, loss or deduction with respect to those units would not be reportable by the unitholder;
- any cash distributions received by the unitholder for those units would be fully taxable; and
- all of these distributions would appear to be ordinary income.

Counsel has not rendered an opinion regarding the treatment of a unitholder where common units are loaned to a short seller to cover a short sale of common units; therefore, unitholders desiring to ensure their status as partners and avoid the risk of gain recognition from a loan to a short seller should modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units. The IRS has announced that it is actively studying issues relating to the tax treatment of short sales of partnership interests. Please read " Disposition of Common Units Recognition of Gain or Loss."

Alternative Minimum Tax. Although it is not expected that we will generate significant tax preference items or adjustments, each unitholder will be required to take into account his distributive share of any items of our income, gain, loss or deduction for purposes of the alternative minimum tax. The current minimum tax rate for noncorporate taxpayers is 26% on the first $175,000 of alternative minimum taxable income in excess of the exemption amount and 28% on any additional alternative minimum taxable income. Prospective unitholders should consult with their tax advisors as to the impact of an investment in units on their liability for the alternative minimum tax.

Tax Rates. In general the highest effective United States federal income tax rate for individuals currently is 35% and the maximum United States federal income tax rate for net capital gains of an individual currently is 15% if the asset disposed of was held for more than 12 months at the time of disposition.

Section 754 Election. We have made the election permitted by Section 754 of the Internal Revenue Code. That election is irrevocable without the consent of the IRS. The election will generally permit us to adjust a common unit purchaser's tax basis in our assets ("inside basis") under Section 743(b) of the Internal Revenue Code to reflect his purchase price. This election does not apply to a person who purchases common units directly from us. The Section 743(b) adjustment belongs to the purchaser and not to other partners. For purposes of this discussion, a partner's inside basis in our assets will be considered to have two components: (1) his share of our tax basis in our assets ("common basis") and (2) his Section 743(b) adjustment to that basis.

Treasury regulations under Section 743 of the Internal Revenue Code require, if the remedial allocation method is adopted (which we have adopted), a portion of the Section 743(b) adjustment attributable to recovery property to be depreciated over the remaining cost recovery period for the Section 704(c) built-in gain. Under Treasury Regulation Section 1.167(c)-l(a)(6), a Section 743(b) adjustment attributable to property subject to depreciation under Section 167 of the Internal Revenue Code rather than cost recovery deductions under Section 168 is generally required to be depreciated using either the straight-line method or the 150% declining balance method. Under our partnership agreement, the general partner is authorized to take a position to preserve the uniformity of units even if that position is not consistent with these Treasury Regulations. Please read " Tax Treatment of Operations" and " Uniformity of Units."

Although counsel is unable to opine as to the validity of this approach because there is no clear authority on this issue, we intend to depreciate the portion of a Section 743(b) adjustment attributable to unrealized appreciation in the value of Contributed Property, to the extent of any unamortized Book-Tax Disparity, using a rate of depreciation or amortization derived from the depreciation or amortization method and useful life applied to the common basis of the property, or treat that portion as non-amortizable to the extent attributable to property the common basis of which is not amortizable. This method is consistent with the regulations under Section 743 but is arguably inconsistent with Treasury Regulation Section 1.167(c)-1(a)(6), which is not expected to directly apply to a material portion of our assets. To the extent this Section 743(b) adjustment is attributable to appreciation in value in excess of the unamortized Book-Tax Disparity, we will apply the rules described in the Treasury Regulations and legislative history. If we determine that this position cannot reasonably be taken, we may take a depreciation or amortization position under which all purchasers acquiring units in the same month would receive depreciation or amortization, whether attributable to common basis or a Section 743(b) adjustment, based upon the same applicable rate as if they had purchased a direct interest in our assets. This kind of aggregate approach may result in lower annual depreciation or amortization deductions than would otherwise be allowable to some unitholders. Please read Uniformity of Units."

A Section 754 election is advantageous if the transferee's tax basis in his units is higher than the units' share of the aggregate tax basis of our assets immediately prior to the transfer. In that case, as a result of the election, the transferee would have, among other items, a greater amount of depreciation and depletion deductions and a smaller share of any gain or loss on a sale of our assets. Conversely, a Section 754 election is disadvantageous if the transferee's tax basis in his units is lower than those units' share of the aggregate tax basis of our assets immediately prior to the transfer. Thus, the fair market value of the units may be affected either favorably or unfavorably by the election.

The calculations involved in the Section 754 election are complex and will be made on the basis of assumptions as to the value of our assets and other matters. The determinations we make may be successfully challenged by the IRS and the deductions resulting from them may be reduced or disallowed altogether. For example, the allocation of the Section 743(b) adjustment among our assets must be made in accordance with the Internal Revenue Code. The IRS could seek to reallocate some or all of any Section 743(b) adjustment allocated by us to our tangible assets to goodwill instead. Goodwill, as an intangible asset, is generally amortizable over a longer period of time or under a less accelerated method than our tangible assets. Should the IRS require a different basis adjustment to be made, and should, in our opinion, the expense of compliance exceed the benefit of the election, we may seek permission from the IRS to revoke our Section 754 election. If permission is granted, a subsequent purchaser of units may be allocated more income than he would have been allocated had the election not been revoked.

Tax Treatment of Operations

Accounting Method and Taxable Year. We use the year ending December 31 as our taxable year and the accrual method of accounting for federal income tax purposes. Each unitholder will be required to include in income his share of our income, gain, loss and deduction for our taxable year ending within or with his taxable year. In addition, a unitholder who has a taxable year ending on a date other than December 31 and who disposes of all of his units following the close of our taxable year but before the close of his taxable year must include his share of our income, gain, loss and deduction in income for his taxable year, with the result that he will be required to include in income for his taxable year his share of more than one year of our income, gain, loss and deduction. Please read " Disposition of Common Units Allocations Between Transferors and Transferees."

Initial Tax Basis, Depreciation and Amortization. The tax basis of our assets will be used for purposes of computing depreciation and cost recovery deductions and, ultimately, gain or loss on the disposition of these assets. The federal income tax burden associated with the difference between the fair market value of our assets and their tax basis immediately prior to this offering will be borne by partners holding interests in us prior to this offering. Please read " Tax Consequences of Unit Ownership Allocation of Income, Gain, Loss and Deduction."

To the extent allowable, we may elect to use the depreciation and cost recovery methods that will result in the largest deductions being taken in the early years after assets are placed in service. We are not entitled to any amortization deductions with respect to any goodwill conveyed to us on formation. Property we subsequently acquire or construct may be depreciated using accelerated methods permitted by the Internal Revenue Code.

If we dispose of depreciable property by sale, foreclosure, or otherwise, all or a portion of any gain, determined by reference to the amount of depreciation previously deducted and the nature of the property, may be subject to the recapture rules and taxed as ordinary income rather than capital gain. Similarly, a partner who has taken cost recovery or depreciation deductions with respect to property we own will likely be required to recapture some or all of those deductions as ordinary income upon a sale of his interest in us. Please read " Tax Consequences of Unit Ownership Allocation of Income, Gain, Loss and Deduction" and " Disposition of Common Units Recognition of Gain or Loss."

The costs incurred in selling our units (called "syndication expenses") must be capitalized and cannot be deducted currently, ratably or upon our termination. There are uncertainties regarding the classification of costs as organization expenses, which may be amortized by us, and as syndication expenses, which may not be amortized by us. The underwriting discounts and commissions we incur will be treated as syndication expenses.

Valuation and Tax Basis of Our Properties. The federal income tax consequences of the ownership and disposition of units will depend in part on our estimates of the relative fair market values, and the initial tax bases, of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we will make many of the relative fair market value estimates ourselves. These estimates of basis are subject to challenge and will not be binding on the IRS or the courts. If the estimates of fair market value or basis are later found to be incorrect, the character and amount of items of income, gain, loss or deductions previously reported by unitholders might change, and unitholders might be required to adjust their tax liability for prior years and may incur interest and penalties with respect to those adjustments.

Disposition of Common Units

Recognition of Gain or Loss. Gain or loss will be recognized on a sale of units equal to the difference between the amount realized and the unitholder's tax basis for the units sold. A unitholder's amount realized will be measured by the sum of the cash or the fair market value of other property received plus his share of our nonrecourse liabilities. Because the amount realized includes a unitholder's share of our nonrecourse liabilities, the gain recognized on the sale of units could result in a tax liability in excess of any cash received from the sale.

Prior distributions from us in excess of cumulative net taxable income for a common unit that decreased a unitholder's tax basis in that common unit will, in effect, become taxable income if the common unit is sold at a price greater than the unitholder's tax basis in that common unit, even if the price is less than his original cost.

Except as noted below, gain or loss recognized by a unitholder, other than a "dealer" in units, on the sale or exchange of a unit held for more than one year will generally be taxable as capital gain or loss. Capital gain recognized by an individual on the sale of units held more than 12 months will generally be taxed a maximum rate of 15%. A portion of this gain or loss, which will likely be substantial, however, will be separately computed and taxed as ordinary income or loss under Section 751 of the Internal Revenue Code to the extent attributable to assets giving rise to depreciation recapture or other "unrealized receivables" or to "inventory items" we own. The term "unrealized receivables" includes potential recapture items, including depreciation recapture. Ordinary income attributable to unrealized receivables, inventory items and depreciation recapture may exceed net taxable gain realized upon the sale of a unit and may be recognized even if there is a net taxable loss realized on the sale of a unit. Thus, a unitholder may recognize both ordinary income and a capital loss upon a sale of units. Capital losses may offset capital gains and no more than $3,000 of ordinary income in the case of individuals, and may only be used to offset capital gains in the case of corporations.

The IRS has ruled that a partner who acquires interests in a partnership in separate transactions must combine those interests and maintain a single adjusted tax basis for all those interests. Upon a sale or other disposition of less than all of those interests, a portion of that tax basis must be allocated to the interests sold using an "equitable apportionment" method. Although the ruling is unclear as to how the holding period of these interests is determined once they are combined, Treasury regulations allow a selling unitholder who can identify common units transferred with an ascertainable holding period to elect to use the actual holding period of the common units transferred. Thus, according to the ruling, a common unitholder will be unable to select high or low basis common units to sell as would be the case with corporate stock, but, according to the regulations, may designate specific common units sold for purposes of determining the holding period of units transferred. A unitholder electing to use the actual holding period of common units transferred must consistently use that identification method for all subsequent sales or exchanges of common units. A unitholder considering the purchase of additional units or a sale of common units purchased in separate transactions should consult his tax advisor as to the possible consequences of this ruling and application of the regulations.

Specific provisions of the Internal Revenue Code affect the taxation of some financial products and securities, including partnership interests, by treating a taxpayer as having sold an "appreciated" partnership interest, one in which gain would be recognized if it were sold, assigned or terminated at its fair market value, if the taxpayer or related persons enter(s) into:

- a short sale;
- a futures or forward contract with respect to the partnership interest or substantially identical property.

Moreover, if a taxpayer has previously entered into a short sale, an offsetting notional principal contract or a futures or forward contract with respect to the partnership interest, the taxpayer will be treated as having sold that position if the taxpayer or a related person then acquires the partnership interest or substantially identical property. The Secretary of Treasury is also authorized to issue regulations that treat a taxpayer that enters into transactions or positions that have substantially the same effect as the preceding transactions as having constructively sold the financial position.

Allocations Between Transferors and Transferees. In general, our taxable income and losses will be determined annually, will be prorated on a monthly basis and will be subsequently apportioned among the unitholders in proportion to the number of units owned by each of them as of the opening of the NYSE on the first business day of the month (the "Allocation Date"). However, gain or loss realized on a sale or other disposition of our assets other than in the ordinary course of business will be allocated among the unitholders on the Allocation Date in the month in which that gain or loss is recognized. As a result, a unitholder transferring units may be allocated income, gain, loss and deduction realized after the date of transfer.

The use of this method may not be permitted under existing Treasury regulations. Accordingly, counsel is unable to opine on the validity of this method of allocating income and deductions between unitholders. If this method is not allowed under the Treasury regulations, or only applies to transfers of less than all of the unitholder's interest, our taxable income or losses might be reallocated among the unitholders. We are authorized to revise our method of allocation between unitholders to conform to a method permitted under future Treasury Regulations.

A unitholder who owns units at any time during a quarter and who disposes of them prior to the record date set for a cash distribution for that quarter will be allocated items of our income, gain, loss and deductions attributable to that quarter but will not be entitled to receive that cash distribution.

Notification Requirements. A unitholder who sells or exchanges units is required to notify us in writing of that sale or exchange within 30 days after the sale or exchange. We are required to notify the IRS of that transaction and to furnish specified information to the transferor and transferee. However, these reporting requirements do not apply to a sale by an individual who is a citizen of the United States and who effects the sale or exchange through a broker. Additionally, a transferor and a transferee of a unit will be required to furnish statements to the IRS, filed with their income tax returns for the taxable year in which the sale or exchange occurred, that describe the amount of the consideration received for the unit that is allocated to our goodwill or going concern value. Failure to satisfy these reporting obligations may lead to the imposition of substantial penalties.

Constructive Termination. We will be considered to have been terminated for tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a 12-month period. A constructive termination results in the closing of our taxable year for all unitholders. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may result in more than 12 months of our taxable income or loss being includable in his taxable income for the year of termination. We would be required to make new tax elections after a termination, including a new election under Section 754 of the Internal Revenue Code, and a termination would result in a deferral of our deductions for depreciation. A termination could also result in penalties if we were unable to determine that the termination had occurred. Moreover, a termination might either accelerate the application of, or subject us to, any tax legislation enacted before the termination.

Uniformity of Units

Because we cannot match transferors and transferees of units, we must maintain uniformity of the economic and tax characteristics of the units to a purchaser of these units. In the absence of uniformity, we may be unable to completely comply with a number of federal income tax requirements, both statutory and regulatory. A lack of uniformity can result from a literal application of Treasury

Regulation Section 1.167(c)-i (a)(6). Any non-uniformity could have a negative impact on the value of the units. Please read " Tax Consequences of Unit Ownership Section 754 Election."

We intend to depreciate the portion of a Section 743(b) adjustment attributable to unrealized appreciation in the value of Contributed Property, to the extent of any unamortized Book-Tax Disparity, using a rate of depreciation or amortization derived from the depreciation or amortization method and useful life applied to the common basis of that property, or treat that portion as nonamortizable, to the extent attributable to property the common basis of which is not amortizable, consistent with the regulations under Section 743 even though that portion may be inconsistent with Treasury Regulation Section 1.167(c)-1(a)(6), which is not expected to directly apply to a material portion of our assets. Please read " Tax Consequences of Unit Ownership Section 754 Election." To the extent that the Section 743 (b) adjustment is attributable to appreciation in value in excess of the unamortized Book-Tax Disparity, we will apply the rules described in the Treasury Regulations and legislative history. If we determine that this position cannot reasonably be taken, we may adopt a depreciation and amortization position under which all purchasers acquiring units in the same month would receive depreciation and amortization deductions, whether attributable to a common basis or Section 743(b) adjustment, based upon the same applicable rate as if they had purchased a direct interest in our property. If this position is adopted, it may result in lower annual depreciation and amortization deductions than would otherwise be allowable to some unitholders and risk the loss of depreciation and amortization deductions not taken in the year that these deductions are otherwise allowable. This position will not be adopted if we determine that the loss of depreciation and amortization deductions will have a material adverse effect on the unitholders. If we choose not to utilize this aggregate method, we may use any other reasonable depreciation and amortization method to preserve the uniformity of the intrinsic tax characteristics of any units that would not have a material adverse effect on the unitholders. The IRS may challenge any method of depreciating the Section 743(b) adjustment described in this paragraph. If this challenge were sustained, the uniformity of units might be affected, and the gain from the sale of units might be increased without the benefit of additional deductions. Please read " Disposition of Common Units Recognition of Gain or Loss."

Tax-Exempt Organizations and Other Investors

Ownership of units by employee benefit plans, other tax-exempt organizations, non-resident aliens, foreign corporations, other foreign persons and regulated investment companies raises issues unique to those investors and, as described below, may have substantially adverse tax consequences to them. Employee benefit plans and most other organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, are subject to federal income tax on unrelated business taxable income. Virtually all of our income allocated to a unitholder which is a tax-exempt organization will be unrelated business taxable income and will be taxable to the unitholder.

For tax years beginning on or prior to October 22, 2004, a regulated investment company or "mutual fund" is required to derive 90% or more of its gross income from interest, dividends and gains from the sale of stocks or securities or foreign currency or specified related sources. It is not anticipated that any significant amount of our gross income will include that type of income. Recent legislation adds net income derived from the ownership of an interest in a "qualified publicly traded partnership" to the categories of qualified income for a regulated investment company. We expect that we will meet the definition of a qualified publicly traded partnership. However, this legislation is only effective for taxable years beginning after October 22, 2004.

Non-resident aliens and foreign corporations, trusts or estates that own units will be considered to be engaged in business in the United States because of the ownership of units. As a consequence they will be required to file federal tax returns to report their share of our income, gain, loss or deduction and pay federal income tax at regular rates on their share of our income or gain. And, under rules applicable to publicly traded partnerships, we will withhold tax at the highest effective applicable rate from cash distributions made quarterly to foreign unitholders. Each foreign unitholder must obtain a taxpayer identification number from the IRS and submit that number to our transfer agent on a Form W-8 BEN or applicable substitute form in order to obtain credit for these withholding taxes.

In addition, because a foreign corporation that owns units will be treated as engaged in a United States trade or business, that corporation may be subject to United States branch profits tax at a rate of 30%, in addition to regular federal income tax, on its share of our income and gain, as adjusted for changes in the foreign corporation's "U.S. net equity," which is effectively connected with the conduct of a United States trade or business. That tax may be reduced or eliminated by an income tax treaty between the United States and the country in which the foreign corporate unitholder is a "qualified resident." In addition, this type of unitholder is subject to special information reporting requirements under Section 6038C of the Internal Revenue Code.

Under a ruling of the IRS, a foreign unitholder who sells or otherwise disposes of a unit will be subject to federal income tax on gain realized on the disposition of that unit to the extent that this gain is effectively connected with a United States trade or business of the foreign unitholder. Apart from the ruling, a foreign unitholder will not be taxed or subject to withholding upon the disposition of a unit if he has owned less than 5% in value of the units during the five-year period ending on the date of the disposition and if the units are regularly traded on an established securities market at the time of the disposition.

Administrative Matters

Information Returns and Audit Procedures. We intend to furnish to each unitholder, within 90 days after the close of each calendar year, specific tax information, including a Schedule K-1, which describes his share of our income, gain, loss and deduction for our preceding taxable year. In preparing this information, which will not be reviewed by counsel, we will take various accounting and reporting positions, some of which have been mentioned earlier, to determine the unitholder's share of income, gain, loss and deduction. We cannot assure you that those positions will yield a result that conforms to the requirements of the Internal Revenue Code, regulations or administrative interpretations of the IRS. Neither we nor counsel can assure prospective unitholders that the IRS will not successfully contend in court that those positions are impermissible. Any challenge by the IRS could negatively affect the value of the units.

The IRS may audit our federal income tax information returns. Adjustments resulting from an IRS audit may require each unitholder to adjust a prior year's tax liability, and possibly may result in an audit of that unitholder's own return. Any audit of a unitholder's return could result in adjustments not related to our returns as well as those related to our returns.

Partnerships generally are treated as separate entities for purposes of federal tax audits, judicial review of administrative adjustments by the IRS and tax settlement proceedings. The tax treatment of partnership items of income, gain, loss and deduction are determined in a partnership proceeding rather than in separate proceedings with the partners. The Internal Revenue Code requires that one partner be designated as the "Tax Matters Partner" for these purposes. The partnership agreement appoints the general partner as our Tax Matters Partner.

The Tax Matters Partner has made and will make some elections on our behalf and on behalf of unitholders. In addition, the Tax Matters Partner can extend the statute of limitations for assessment of tax deficiencies against unitholders for items in our returns. The Tax Matters Partner may bind a unitholder with less than a 1% profits interest in us to a settlement with the IRS unless that unitholder elects, by filing a statement with the IRS, not to give that authority to the Tax Matters Partner. The Tax Matters Partner may seek judicial review, by which all the unitholders are bound, of a final partnership administrative adjustment and, if the Tax Matters Partner fails to seek judicial review, judicial review may be sought by any unitholder having at least a 1% interest in profits or by any group of unitholders having in the aggregate at least a 5% interest in profits. However, only one action for judicial review will go forward, and each unitholder with an interest in the outcome may participate. However, if we elect to be treated as a large partnership, a unitholder will not have the right to participate in settlement conferences with the IRS or to seek a refund.

A unitholder must file a statement with the IRS identifying the treatment of any item on his federal income tax return that is not consistent with the treatment of the item on our return. Intentional or negligent disregard of the consistency requirement may subject a unitholder to substantial penalties. However, if we elect to be treated as a large partnership, the unitholders would be required to treat all partnership items in a manner consistent with our return.

Nominee Reporting. Persons who hold an interest in us as a nominee for another person are required to furnish to us:

- the name, address and taxpayer identification number of the beneficial owner and the nominee;
- whether the beneficial owner is
  - a person that is not a United States person,
  - a foreign government, an international organization or any wholly owned agency or instrumentality of either of the foregoing, or
  - a tax-exempt entity;
- the amount and description of units held, acquired or transferred for the beneficial owner; and
- specific information including the dates of acquisitions and transfers, means of acquisitions and transfers, and acquisition cost for purchases, as well as the amount of net proceeds from sales.

Brokers and financial institutions are required to furnish additional information, including whether they are United States persons and specific information on units they acquire, hold or transfer for their own account. A penalty of $50 per failure, up to a maximum of $100,000 per calendar year, is imposed by the Internal Revenue Code for failure to report that information to us. The nominee is required to supply the beneficial owner of the units with the information furnished to us.

Accuracy-related Penalties. An additional tax equal to 20% of the amount of any portion of an underpayment of tax that is attributable to one or more specified causes, including negligence or disregard of rules or regulations, substantial understatements of income tax and substantial valuation misstatements, is imposed by the Internal Revenue Code. No penalty will be imposed, however, for any portion of an underpayment if it is shown that there was a reasonable cause for that portion and that the taxpayer acted in good faith regarding that portion.

A substantial understatement of income tax in any taxable year exists if the amount of the understatement exceeds the greater of 10% of the tax required to be shown on the return for the taxable year or $5,000. The amount of any understatement subject to penalty generally is reduced if any portion is attributable to a position adopted on the return:

- for which there is, or was, "substantial authority," or
- as to which there is a reasonable basis and the pertinent facts of that position are disclosed on the return.

If any item of income, gain, loss or deduction included in the distributive shares of unitholders might result in that kind of an "understatement" of income for which no "substantial authority" exists, we must disclose the pertinent facts on our return. In addition, we will make a reasonable effort to furnish sufficient information for unitholders to make adequate disclosure on their returns to avoid liability for this penalty. More stringent rules apply to "tax shelters," which we do not believe includes us.

A substantial valuation misstatement exists if the value of any property, or the adjusted basis of any property, claimed on a tax return is 200% or more of the amount determined to be the correct amount of the valuation or adjusted basis. No penalty is imposed unless the portion of the underpayment attributable to a substantial valuation misstatement exceeds $5,000. If the valuation claimed on a return is 400% or more than the correct valuation, the penalty imposed increases to 40%.

Reportable Transactions. If we were to engage in a "reportable transaction," we (and possibly you and others) would be required to make a detailed disclosure of the transaction to the IRS. A transaction may be a reportable transaction based upon any of several factors, including the fact that it is a type of tax avoidance transaction publicly identified by the IRS as a "listed transaction" or that it produces certain kinds of losses in excess of $2 million. Our participation in a reportable transaction could increase the likelihood that our federal income tax information return (and possibly your tax return) would be audited by the IRS. Please read " Information Returns and Audit Procedures" above.

Moreover, if we were to participate in a reportable transaction with a significant purpose to avoid or evade tax, or in any listed transaction, you may be subject to the following provisions of the American Jobs Creation Act of 2004:

- accuracy-related penalties with a broader scope, significantly narrower exceptions, and potentially greater amounts than described above at " Accuracy-related Penalties,"
- for those persons otherwise entitled to deduct interest on federal tax deficiencies, nondeductibility of interest on any resulting tax liability and
- in the case of a listed transaction, an extended statute of limitations.

We do not expect to engage in any "reportable transactions."

State, Local and Other Tax Considerations

In addition to federal income taxes, you may be subject to other taxes, such as state and local and Canadian federal and provincial taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that may be imposed by the various jurisdictions in which we do business or own property. Although an analysis of those various taxes is not presented herein, each prospective unitholder should consider their potential impact on his investment in us. We will own property or conduct business in Canada and in most states of the United States. A unitholder may be required to file Canadian federal income tax returns and to pay Canadian federal and provincial income taxes and to file state income tax returns and to pay taxes in various states and may be subject to penalties for failure to comply with such requirements. In certain states, tax losses may not produce a tax benefit in the year incurred (if, for example, we have no income from sources within that state) and also may not be available to offset income in subsequent taxable years. Some of the states may require us to withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the state. Withholding, the amount of which may be greater or less than a particular unitholder's income tax liability to the state, generally does not relieve the non-resident unitholder from the obligation to file an income tax return. Amounts withheld may be treated as if distributed to unitholders for purposes of determining the amount distributed by us. Please read " Tax Consequences of Unit Ownership." We may also own additional property or do business in other states in the future.

It is the responsibility of each unitholder to investigate the legal and tax consequences, under the laws of pertinent states and localities, including the Canadian provinces and Canada, of his investment in us. Accordingly, each prospective unitholder should consult, and must depend upon, his own tax counsel or other advisor with regard to those matters. Further, it is the responsibility of each unitholder to file all Canadian, Canadian province, state and local, as well as federal tax returns that may be required of him. Counsel has not rendered an opinion on the Canadian federal, Canadian provincial, state or local tax consequences of an investment in us.

SELLING UNITHOLDERS

This prospectus covers the offering for resale of up to 19,461,702 common units by selling unitholders. No such sales may occur unless the selling unitholder has notified us of his or her intention to sell our common units and this prospectus has been declared effective by the SEC, and remains effective at the time such selling unitholder offers or sells such common units. We are required to update this prospectus to reflect material developments in our business, financial position and results of operations. The following table sets forth information relating to the selling unitholders' beneficial ownership of our common units:

Selling Unitholders	Number of Common Units Owned Prior to the Offering	Amount of Common Units being Offered	Amount of Units to be Owned after Completion of the Offering	Percentage of Common Units to be Owned after Completion of the Offering
Plains Holdings II Inc.[1]	11,082,930	11,082,930	0	
Plains Holdings Inc.[1]	1,307,190	1,307,190	0	
Plains AAP, L.P.[2]	439,370	439,370	0	
Sable Holdings, L.P.	609,446	609,446	0	
Kayne Anderson Capital Advisors, L.P.[4]	5,355,391	3,055,887	2,299,504	3.4%
Vulcan Private Equity I LLC[5]	1,298,280	1,298,280	0	
Tortoise Energy Infrastructure Corporation	1,215,255	1,142,760	72,495	*
Wachovia Investors, Inc.	328,668	328,668	0	
Strome Hedgecap Fund, L.P.	100,000	100,000	0	
John T. Raymond[3]	403,117	97,171	305,946	*

* Less than 1%.

(1) Plains Holdings Inc. is our former general partner. Plains Holdings II Inc. is a wholly owned subsidiary of Plains Holdings Inc.

(2) Plains AAP, L.P. is our general partner and maintains a Performance Option Plan funded by 439,370 common units. To the extent any options on these units are exercised on a cashless basis by their holders, our general partner may sell any units it retains after such exercise pursuant to this prospectus.

(3) Mr. Raymond served on our board of directors from July 2001 to April 2005. Mr. Raymond is a director of Vulcan Energy Corporation. Mr. Raymond disclaims any deemed beneficial ownership of any units held by Vulcan Energy Corporation or its affiliates.

(4) Various accounts (including KAFU Holdings, L.P., which owns a portion of our general partner) under the management or control of Kayne Anderson Capital Advisors, L.P., the general partner of which is Kayne Anderson Investment Management, Inc., own common units. Mr. Sinnott, the Vice President of Kayne Anderson Investment Management, Inc., has been designated as one of our directors by KAFU Holdings, L.P. Mr. Sinnott disclaims any deemed beneficial ownership of any units held by KAFU Holdings, L.P. or its affiliates, other than through his 4.5% limited partner interest in KAFU Holdings, L.P.

(5) Mr. Paul Allen controls Vulcan Private Equity I LLC, which is the record holder of 1,298,280 common units. In addition, Mr. Allen owns approximately 88.38% of the outstanding shares of common stock of Vulcan Energy Corporation. Vulcan Energy Corporation is the indirect sole stockholder of Plains Holdings Inc., which owns 1,307,190 of our common units. Plains Holdings II owns 11,082,930 of our common units. Plains Holdings Inc. owns 44% of the equity of our general partner. Mr. Allen disclaims any deemed beneficial ownership, beyond his pecuniary interest, in any of our partner interests held by Plains Holdings or any of its affiliates. See "Security Ownership of Certain Beneficial Owners and Management and Related Unitholders' Matters."

Any prospectus supplement reflecting a sale of common units hereunder will set forth, with respect to the selling unitholders:

- the name of the selling unitholders;

- the nature of the position, office or other material relationship which the selling unitholders will have had within the prior three years with us or any of our affiliates;

- the number of common units owned by the selling unitholders prior to the offering;

- the amount of common units to be offered for the selling unitholders' account; and

- the amount and (if one percent or more) the percentage of common units to be owned by the selling unitholders after the completion of the offering.

All expenses incurred with the registration of the common units owned by the selling unitholders will be borne by us.

PLAN OF DISTRIBUTION

We are registering the common units on behalf of the selling unitholders. As used in this prospectus, "selling unitholders" includes donees and pledgees selling common units received from a named selling unitholder after the date of this prospectus.

Under this prospectus, the selling unitholders intend to offer our securities to the public:

- through one or more broker-dealers;
- through underwriters; or
- directly to investors.

The selling unitholders may price the common units offered from time to time:

- at market prices prevailing at the time of any sale under this registration statement;
- at prices related to market prices; or
- at negotiated prices.

We will pay the costs and expenses of the registration and offering of the common units offered hereby. We will not pay any underwriting fees, discounts and selling commissions allocable to each selling unitholder's sale of its respective common units, which will be paid by the selling unitholders. Broker-dealers may act as agent or may purchase securities as principal and thereafter resell the securities from time to time:

- in or through one or more transactions (which may involve crosses and block transactions) or distributions;
- on the New York Stock Exchange;
- in the over-the-counter market; or
- in private transactions.

Broker-dealers or underwriters may receive compensation in the form of underwriting discounts or commissions and may receive commissions from purchasers of the securities for whom they may act as agents. If any broker-dealer purchases the securities as principal, it may effect resales of the securities from time to time to or through other broker-dealers, and other broker-dealers may receive compensation in the form of concessions or commissions from the purchasers of securities for whom they may act as agents.

To the extent required, the names of the specific managing underwriter or underwriters, if any, as well as other important information, will be set forth in prospectus supplements. In that event, the discounts and commissions the selling unitholders will allow or pay to the underwriters, if any, and the discounts and commissions the underwriters may allow or pay to dealers or agents, if any, will be set forth in, or may be calculated from, the prospectus supplements. Any underwriters, brokers, dealers and agents who participate in any sale of the securities may also engage in transactions with, or perform services for, us or our affiliates in the ordinary course of their businesses.

In addition, the selling unitholders have advised us that they may sell common units in compliance with Rule 144, if available, or pursuant to other available exemptions from the registration requirements under the Securities Act, rather than pursuant to this prospectus.

To the extent required, this prospectus may be amended or supplemented from time to time to describe a specific plan of distribution.

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In connection with offerings under this shelf registration and in compliance with applicable law, underwriters, brokers or dealers may engage in transactions which stabilize or maintain the market price of the securities at levels above those which might otherwise prevail in the open market. Specifically, underwriters, brokers or dealers may over-allot in connection with offerings, creating a short position in the securities for their own accounts. For the purpose of covering a syndicate short position or stabilizing the price of the securities, the underwriters, brokers or dealers may place bids for the securities or effect purchases of the securities in the open market. Finally, the underwriters may impose a penalty whereby selling concessions allowed to syndicate members or other brokers or dealers for distribution the securities in offerings may be reclaimed by the syndicate if the syndicate repurchases previously distributed securities in transactions to cover short positions, in stabilization transactions or otherwise. These activities may stabilize, maintain or otherwise affect the market price of the securities, which may be higher than the price that might otherwise prevail in the open market, and, if commenced, may be discontinued at any time.

VALIDITY OF THE COMMON UNITS

The validity of the common units will be passed upon for Plains All American Pipeline by Vinson & Elkins L.L.P., Houston, Texas. The selling unitholders' counsel and the underwriters' own legal counsel will advise them about other issues relating to any offering in which they participate.

EXPERTS

The financial statements as of December 31, 2004 and 2003 and for each of the three years in the period ended December 31, 2004 and management's assessment of the effectiveness of internal control over financial reporting (which is included in Management's Report on Internal Control over Financial Reporting) as of December 31, 2004 included in this Prospectus have been so included in reliance on the report of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

The balance sheet as of December 31, 2004 of Plains AAP, L.P. included in this Prospectus has been so included in reliance on the report of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

WHERE YOU CAN FIND MORE INFORMATION

We file annual, quarterly and special reports and other information with the Securities and Exchange Commission under the Securities Exchange Act of 1934. You can inspect and/or copy these reports and other information at offices maintained by the SEC, including:

- the principal offices of the SEC located at Judiciary Plaza, 450 Fifth Street, N.W., Room 1024, Washington, D.C. 20549;
- the SEC's website at *http://www.sec.gov*.

In addition, please call the SEC at 1-800-732-0330 for further information on their public reference room.

Further, our common units are listed on the New York Stock Exchange, and you can inspect similar information at the offices of the New York Stock Exchange, located at 20 Broad Street, New York, New York 10005.

You can read and copy any of our materials filed with the SEC at our website at *http://www.paalp.com* or you may request a copy of these filings at no cost by making written or telephone requests for copies to:

Plains All American Pipeline, L.P.
333 Clay Street, Suite 1600
Houston, Texas 77002
Attention: Tim Moore
Telephone: (713) 646-4100

You should rely only on the information provided in this prospectus. The information contained on our website is not a part of this prospectus. We have not authorized anyone else to provide you with any information. You should not assume that the information provided in this prospectus is accurate as of any date other than the date on the cover of this prospectus.

FORWARD-LOOKING STATEMENTS

All statements, other than statements of historical fact, included in this report are forward-looking statements, including, but not limited to, statements identified by the words "anticipate," "believe," "estimate," "expect," "plan," "intend" and "forecast," and similar expressions and statements regarding our business strategy, plans and objectives of our management for future operations. These statements reflect our current views with respect to future events, based on what we believe are reasonable assumptions. Certain factors could cause actual results to differ materially from results anticipated in the forward-looking statements. These factors include, but are not limited to:

- abrupt or severe production declines or production interruptions in outer continental shelf production located offshore California and transported on our pipeline system;
- the success of our risk management activities;
- the availability of, and our ability to consummate, acquisition or combination opportunities;
- our access to capital to fund additional acquisitions and our ability to obtain debt or equity financing on satisfactory terms;
- successful integration and future performance of acquired assets or businesses;
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
- maintenance of our credit rating and ability to receive open credit from our suppliers;
- declines in volumes shipped on the Basin Pipeline, Capline Pipeline and our other pipelines by third party shippers;
- the availability of adequate third party production volumes for transportation and marketing in the areas in which we operate;
- successful third party drilling efforts in areas in which we operate pipelines or gather crude oil;
- demand for various grades of crude oil and resulting changes in pricing conditions or transmission throughput requirements;
- fluctuations in refinery capacity in areas supplied by our transmission lines;
- the effects of competition;
- continued creditworthiness of, and performance by, counter parties;
- the impact of crude oil price fluctuations;
- the impact of current and future laws, rulings and governmental regulations;

- shortages or cost increases of power supplies, materials or labor;
- weather interference with business operations or project construction;
- the currency exchange rate of the Canadian dollar;
- fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our Long-Term Incentive Plan; and
- general economic, market or business conditions.

Other factors described herein, or factors that are unknown or unpredictable, could also have a material adverse effect on future results. Please read "Risk Factors" and "Management's Discussion and Analysis of Financial Condition and Results of Operations." Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

INDEX TO FINANCIAL STATEMENTS

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands, except unit data)

	March 31, 2005	December 31, 2004
	(unaudited)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 21,839	$ 12,988
Trade accounts receivable, net	1,030,139	521,785
Inventory	711,280	498,200
Other current assets	82,510	68,229
Total current assets	1,845,768	1,101,202
PROPERTY AND EQUIPMENT	1,977,606	1,911,509
Accumulated depreciation	(201,657)	(183,887)
	1,775,949	1,727,622
OTHER ASSETS		
Pipeline linefill in owned assets	166,147	168,352
Inventory in third party assets	55,271	59,279
Other, net	91,067	103,956
Total assets	$ 3,934,202	$ 3,160,411
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable	$ 1,270,276	$ 850,912
Due to related parties	35,277	32,897
Short-term debt	560,962	175,472
Other current liabilities	94,801	54,436
Total current liabilities	1,961,316	1,113,717
LONG-TERM LIABILITIES		
Long-term debt under credit facilities and other	132,880	151,753
Senior notes, net of unamortized discount of $2,640 and $2,729, respectively	797,360	797,271
Other long-term liabilities and deferred credits	32,089	27,466
Total liabilities	2,923,645	2,090,207
COMMITMENTS AND CONTINGENCIES (NOTE 9)		

	March 31, 2005		December 31, 2004
PARTNERS' CAPITAL			
Common unitholders (67,868,108 and 62,740,218 units outstanding at March 31, 2005, and December 31, 2004, respectively)	980,569		919,826
Class B common unitholder (no units and 1,307,190 units outstanding at March 31, 2005 and December 31, 2004, respectively)			18,775
Class C common unitholders (no units and 3,245,700 units outstanding at March 31, 2005 and December 31, 2004, respectively)			100,423
General partner	29,988		31,180
Total partners' capital	1,010,557		1,070,204
	$ 3,934,202	$	3,160,411

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per unit data)

	Three Months Ended March 31,	
	2005	2004
	(unaudited)	
REVENUES		
Crude oil and LPG sales (includes approximately $3,419,049 and $1,834,857, respectively, related to buy/sell transactions)	$ 6,417,789	$ 3,623,482
Other gathering, marketing, terminalling and storage revenues	8,173	7,621
Pipeline margin activities revenues (includes approximately $33,508 and $46,424, respectively, related to buy/sell transactions)	157,627	142,335
Pipeline tariff activities revenues	54,907	31,206
Total revenues	6,638,496	3,804,644
COSTS AND EXPENSES		
Crude oil and LPG purchases and related costs (includes purchases of approximately $3,397,536 and $1,791,634, respectively, related to buy/sell transactions)	6,334,646	3,557,071
Pipeline margin activities purchases (includes approximately $31,499 and $44,343, respectively, related to buy/sell transactions)	151,514	136,434
Field operating costs (excluding LTIP charge)	63,476	37,816
LTIP charge operations	344	567
General and administrative expenses (excluding LTIP charge)	20,216	15,478
LTIP charge general and administrative	1,895	3,661
Depreciation and amortization	19,118	13,120
Total costs and expenses	6,591,209	3,764,147
OPERATING INCOME	47,287	40,497
OTHER INCOME (EXPENSE)		
Interest expense (net of capitalized interest of $620 and $178, respectively)	(14,558)	(9,532)
Interest and other income (expense), net	79	41
Income before cumulative effect of change in accounting principle	32,808	31,006
Cumulative effect of change in accounting principle		(3,130)
NET INCOME	$ 32,808	$ 27,876
NET INCOME LIMITED PARTNERS	$ 29,265	$ 25,707
NET INCOME GENERAL PARTNER	$ 3,543	$ 2,169
BASIC NET INCOME PER LIMITED PARTNER UNIT		
Income before cumulative effect of change in accounting principle	$ 0.43	$ 0.49
Cumulative effect of change in accounting principle		(0.05)

	Three Months Ended March 31,	
Basic net income per limited partner unit	$ 0.43	$ 0.44
DILUTED NET INCOME PER LIMITED PARNTER UNIT		
Income before cumulative effect of change in accounting principle	$ 0.43	$ 0.49
Cumulative effect of change in accounting principle		(0.05)
Diluted net income per limited partner unit	$ 0.43	$ 0.44
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	67,517	58,414
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	68,156	59,017

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Three Months Ended March 31, 2005	Three Months Ended March 31, 2004
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 32,808	27,876
Adjustments to reconcile to cash flows from operating activities:		
Depreciation and amortization	19,118	13,120
Cumulative effect of change in accounting principle		3,130
Change in derivative fair value	13,406	(7,498)
LTIP charge	2,239	4,228
Noncash amortization of terminated interest rate swap	387	357
Noncash loss on foreign currency revaluation	544	410
Changes in assets and liabilities, net of acquisitions:		
Trade accounts receivable and other	(554,814)	34,620
Inventory	(208,035)	32,473
Accounts payable and other current liabilities	420,145	24,711
Due to related parties	2,353	(446)
Net cash provided by (used in) operating activities	(271,849)	132,981
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions	(13,467)	(143,228)
Additions to property and equipment	(50,011)	(13,325)
Proceeds from sales of assets	1,758	650
Net cash used in investing activities	(61,720)	(155,903)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net borrowings/(repayments) on long-term revolving credit facility	(18,290)	168,720
Net borrowings/(repayments) on working capital revolving credit facility	41,800	(11,200)
Net borrowings/(repayments) on short-term letter of credit and hedged inventory facility	344,600	(100,491)
Net proceeds from the issuance of common units	22,308	88
Distributions paid to unitholders and general partner	(45,005)	(35,174)
Other financing activities	(2,849)	(879)
Net cash provided by financing activities	342,564	21,064
Effect of translation adjustment on cash	(144)	(242)
Net increase (decrease) in cash and cash equivalents	8,851	(2,100)
Cash and cash equivalents, beginning of period	12,988	4,137
Cash and cash equivalents, end of period	$ 21,839	$ 2,037

	Three Months Ended March 31,	
Cash paid for interest, net of amounts capitalized	$ 13,198	$ 2,150

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL
(in thousands)

	Common Units		Class B Common Units		Class C Common Units				
	Units	Amount	Units	Amount	Units	Amount	General Partner Amount	Total Units	Total Partners' Capital Amount
					(unaudited)				
Balance at December 31, 2004	62,740	$ 919,826	1,307	$ 18,775	3,246	$ 100,423	$ 31,180	67,293	$ 1,070,204
Private placement of common units	575	21,860					448	575	22,308
Conversion of Class B Units	1,307	18,323	(1,307)	(18,323)					
Conversion of Class C Units	3,246	99,302			(3,246)	(99,302)			
Distributions		(38,428)		(801)		(1,988)	(3,788)		(45,005)
Net income		27,356		548		1,361	3,543		32,808
Other comprehensive income		(67,670)		(199)		(494)	(1,395)		(69,758)
Balance at March 31, 2005	67,868	$ 980,569		$		$	$ 29,988	67,868	$ 1,010,557

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME AND CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME
(in thousands)

Statements of Comprehensive Income

	Three Months Ended March 31, 2005	Three Months Ended March 31, 2004
	(unaudited)	
Net income	$ 32,808	$ 27,876
Other comprehensive income (loss)	(69,758)	(10,814)
Comprehensive income (loss)	$ (36,950)	$ 17,062

Statement of Changes in Accumulated Other Comprehensive Income

	Net Deferred Gain (Loss) on Derivative Instruments	Currency Translation Adjustments	Total
		(unaudited)	
Balance at December 31, 2004	$ 25,937	$ 70,934	$ 96,871
Current period activity:			
Reclassification adjustments for settled contracts	(1,496)		(1,496)
Changes in fair value of outstanding hedge positions	(65,876)		(65,876)
Currency translation adjustment		(2,386)	(2,386)
Total period activity	(67,372)	(2,386)	(69,758)
Balance at March 31, 2005	$ (41,435)	$ 68,548	$ 27,113

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

Note 1 Organization and Accounting Policies

Plains All American Pipeline, L.P. ("PAA") is a Delaware limited partnership formed in September of 1998. Our operations are conducted directly and indirectly through our operating subsidiaries, Plains Marketing, L.P., Plains Pipeline, L.P. and Plains Marketing Canada, L.P. We are engaged in interstate and intrastate crude oil transportation, and crude oil gathering, marketing, terminalling and storage, as well as the marketing and storage of liquefied petroleum gas and other natural gas related petroleum products. We refer to liquified petroleum gas and natural gas related petroleum products collectively as "LPG." We own an extensive network of pipeline transportation, terminalling, storage and gathering assets in key oil producing basins and at major market hubs in the United States and Canada.

The accompanying consolidated financial statements and related notes present (i) our consolidated financial position as of March 31, 2005, and December 31, 2004, (ii) the results of our consolidated operations for the three months ended March 31, 2005 and 2004, (iii) our consolidated cash flows for the three months ended March 31, 2005 and 2004, (iv) our consolidated changes in partners' capital for the three months ended March 31, 2005, (v) our consolidated comprehensive income for the three months ended March 31, 2005 and 2004, and (vi) our changes in consolidated accumulated other comprehensive income for the three months ended March 31, 2005. The financial statements have been prepared in accordance with the instructions for interim reporting as prescribed by the Securities and Exchange Commission. All adjustments (consisting only of normal recurring adjustments) that in the opinion of management were necessary for a fair statement of the results for the interim periods have been reflected. All significant intercompany transactions have been eliminated. Certain reclassifications are made to prior periods to conform to current period presentation. The results of operations for the three months ended March 31, 2005 should not be taken as indicative of the results to be expected for the full year. The consolidated interim financial statements should be read in conjunction with our consolidated financial statements and notes thereto presented in our 2004 Annual Report on Form 10-K.

Note 2 Trade Accounts Receivable

The majority of our trade accounts receivable relate to our gathering and marketing activities and can generally be described as high volume and low margin activities. As is customary in the industry, a portion of these receivables is reflected net of payables to the same counterparty based on contractual agreements. We routinely review our trade accounts receivable balances to identify past due amounts and analyze the reasons such amounts have not been collected. In many instances, such uncollected amounts involve billing delays and discrepancies or disputes as to the appropriate price, volume or quality of crude oil delivered, received or exchanged. We also attempt to monitor changes in the creditworthiness of our customers as a result of developments related to each customer, the industry as a whole and the general economy. Based on these analyses, as well as our historical experience and the facts and circumstances surrounding certain aged balances, we have established an allowance for doubtful trade accounts receivable. At March 31, 2005, substantially all of our net trade accounts receivable were less than 60 days past the scheduled invoice date. Our allowance for doubtful trade accounts receivable totaled $0.7 million. We consider this reserve adequate; however, there is no assurance that actual amounts will not vary significantly from estimated amounts. The discovery of previously unknown facts or adverse developments affecting one of our counterparties or the industry as a whole could adversely impact our results of operations.

Note 3 Inventory and Linefill

Inventory primarily consists of crude oil and LPG in pipelines, storage tanks and rail cars that is valued at the lower of cost or market, with cost determined using an average cost method. Linefill and minimum working inventory requirements in owned assets are recorded at historical cost and consist of crude oil and LPG used to pack our pipelines such that when an incremental barrel enters, it forces a barrel out at another location, as well as the minimum amount of crude oil and LPG necessary to operate our storage and terminalling facilities.

Linefill and minimum working inventory requirements in third party assets are included in "Inventory" (a current asset) in determining the average cost of operating inventory and applying the lower of cost or market analysis. At the end of each period, we reclassify the linefill in third party assets not expected to be liquidated within the succeeding twelve months out of "Inventory," at average cost, and into "Inventory in Third Party Assets" (a long-term asset), which is reflected as a separate line item within other assets on the consolidated balance sheet.

At March 31, 2005 and December 31, 2004, inventory and linefill consisted of:

	March 31, 2005			December 31, 2004		
	Barrels	$	$/barrel	Barrels	$	$/barrel
	(Barrels in thousands and dollars in millions)					
Inventory[1]						
Crude oil	14,131	$ 679.6	$ 48.09	8,716	$ 396.2	$ 45.46
LPG	845	29.4	$ 34.79	2,857	100.1	$ 35.04
Other		2.3	N/A		1.9	N/A
Inventory subtotal	14,976	711.3		11,573	498.2	
Inventory in third-party assets						
Crude oil	1,249	44.9	$ 35.95	1,294	48.7	$ 37.64
LPG	318	10.4	$ 32.70	318	10.6	$ 33.33
Inventory in third-party assets subtotal	1,567	55.3		1,612	59.3	
Linefill						
Crude oil	5,924	165.3	$ 27.90	6,015	168.4	$ 28.00
LPG	26	0.8	$ 30.77			N/A
Linefill subtotal	5,950	166.1		6,015	168.4	
Total	22,493	$ 932.7		19,200	$ 725.9	

(1) Dollars per barrel reflect the impact of inventory hedges on a portion of our volumes.

Note 4 Debt

Debt consists of the following:

	March 31, 2005	December 31, 2004
Short-term debt:		
Senior secured hedged inventory borrowing facility bearing interest at a rate of 3.5% and 3.0% at March 31, 2005 and December 31, 2004, respectively	$ 425.0	$ 80.4
Working capital borrowings, bearing interest at a rate of 3.7% at March 31, 2005 and December 31, 2004[1]	130.0	88.2
Other	6.0	6.9
Total short-term debt	561.0	175.5
Long-term debt:		
Senior unsecured revolving credit facility, bearing interest at 3.5% at March 31, 2005 and December 31, 2004[1]	$ 125.0	$ 143.6
4.75% senior notes due August 2009, net of unamortized discount of $0.7 million at March 31, 2005 and December 31, 2004	174.3	174.3
7.75% senior notes due October 2012, net of unamortized discount of $0.3 million at March 31, 2005 and December 31, 2004	199.7	199.7
5.63% senior notes due December 2013, net of unamortized discount of $0.6 million at March 31, 2005 and December 31, 2004	249.4	249.4
5.88% senior notes due August 2016, net of unamortized discount of $1.1 million at March 31, 2005 and December 31, 2004	173.9	173.9
Other	7.9	8.1
Total long-term debt[1]	930.2	949.0
Total debt	$ 1,491.2	$ 1,124.5

(1) At March 31, 2005 and December 31, 2004, we have classified $130.0 million and $88.2 million, respectively, of borrowings under our senior unsecured revolving credit facility as short-term. These borrowings are designated as working capital borrowings, must be repaid within one year and are primarily for hedged LPG and crude oil inventory and New York Mercantile Exchange ("NYMEX") margin deposits.

In April 2005, we amended our senior secured hedged inventory facility to increase the capacity under the facility from $425 million to $500 million. We are in the process of negotiating an additional expansion of this facility to increase its capacity by up to $300 million. In addition, in May 2005, we amended our senior unsecured credit facility to increase the capacity from $750 million to $900 million and increased the sub-facility for Canadian borrowings to $360 million. The amended facility can be expanded to $1.25 billion.

During April 2005, we entered into a treasury lock with a large creditworthy financial institution. A treasury lock is a financial derivative instrument that enables the company to lock in the U.S. Treasury Note rate, typically in anticipation of a debt issuance. The treasury lock has a notional principal amount of $75 million and an effective rate of 4.18%. The treasury lock matures in May 2005.

Note 5 Earnings Per Common Unit

The following sets forth the computation of basic and diluted earnings per common unit. The net income available to limited partners and the weighted average limited partner units outstanding have been adjusted for instruments considered common unit equivalents at March 31, 2005 and 2004.

	Three months ended March 31,	
	2005	2004
	(in thousands, except per unit data)	
Net income	$ 32,808	$ 27,876
Less:		
General partner's incentive distribution right	(2,946)	(1,644)
Subtotal	29,862	26,232
General partner 2% ownership	(597)	(525)
Numerator for basic earnings per limited parner unit:		
Net income available for limited partners	29,265	25,707
Effect of dilutive securities:		
Increase in general partner's incentive distribution-contingent equity issuance		(16)
Numerator for diluted earnings per limited partner unit	$ 29,265	$ 25,691
Denominator:		
Denominator for basic earnings per limited partner unit weighted average number of limited partner units	67,517	58,414
Effect of dilutive securities:		
2005 LTIP	639	
Contingent equity issuance		603
Denominator for diluted earnings per limited partner unit weighted average number of limited partner units	68,156	59,017
Basic net income per limited partner unit	$ 0.43	$ 0.44
Diluted net income per limited partner unit	$ 0.43	$ 0.44

Note 6 Partners' Capital and Distributions

Private Placement of Common Units.

On February 25, 2005, we issued 575,000 common units to a subsidiary of Vulcan Energy Corporation. The sale price for the common units was $38.13 per unit resulting in net proceeds, including the general partner's proportionate capital contribution and expenses associated with the sale, of approximately $22.3 million. We intend to use the net proceeds from the private placement to fund a portion of our 2005 expansion capital program. Pending the incurrence of these expenditures, the net proceeds were used to repay indebtedness under our revolving credit facilities.

Conversion of Class B and Class C Common Units.

In accordance with a common unitholder vote at a special meeting on January 20, 2005, each Class B common unit and Class C common unit became convertible into one common unit upon request of the holder. In February 2005, all of the Class B and Class C common units converted into common units.

Distributions

On April 22, 2005, we declared a cash distribution of $0.6375 per unit on our outstanding common units. The distribution is payable on May 13, 2005, to unitholders of record on May 3, 2005, for the period January 1, 2005, through March 31, 2005. The total distribution to be paid is approximately $47.7 million, with approximately $43.3 million to be paid to our common unitholders and $0.9 million and $3.5 million to be paid to our general partner for its general partner and incentive distribution interests, respectively.

On January 25, 2005, we declared a cash distribution of $0.6125 per unit on our outstanding common units, Class B common units and Class C common units. The distribution was paid on February 14, 2005, to unitholders of record on February 4, 2005, for the period October 1, 2004, through December 31, 2004. The total distribution paid was approximately $45.0 million, with approximately $41.2 million paid to our common unitholders and $0.8 million and $3.0 million paid to our general partner for its general partner and incentive distribution interests, respectively.

Note 7 Long-Term Incentive Plans

Our general partner has adopted the Plains All American GP LLC 1998 Long-Term Incentive Plan (the "1998 LTIP") and the 2005 Long-Term Incentive Plan (the "2005 LTIP") for employees and directors of our general partner and its affiliates who perform services for us.

As of March 31, 2005, there are approximately 150,000 phantom units outstanding under the 1998 LTIP, of which we expect approximately 93,000 to vest in May 2005. The majority of the awards outstanding under the 1998 LTIP have performance-based vesting terms and, therefore, we recognize expense when it is considered probable that the awards will vest.

In February 2005, our Board of Directors and Compensation Committee approved grants of approximately 1.9 million phantom units and 1.4 million distribution equivalent rights ("DERs) under the 2005 LTIP. Approximately 1.4 million of the phantom units vest over a six year period (with performance accelerators) while the remaining awards vest over time only if certain performance criteria are met and are forfeited after six years if the performance criteria are not met. No phantom units vest prior to the dates indicated below for each tranche. The DERs vest over time (with performance accelerators) and terminate with the vesting or forfeiture of the related phantom units. The following awards were outstanding under the 2005 LTIP at March 31, 2005.

		Phantom Units			DERs		
Annualized Distribution Rate	**Date**	**A(1)**	**B(2)**	**Total**	**A(1)**	**B(2)**	**Total**
$2.60	May 2007	549	150	699	353	150	503
$2.70	May 2008				132	75	207
$2.80	May 2009	411	150	561	132	75	207
$2.90	May 2010				132	100	232
$3.00	May 2010	411	200	611	132	100	232
		1,371	500	1,871	881	500	1,381

(1) Awards that vest over six years. Achievement of the indicated distribution rate performance criteria can accelerate the vesting to the date indicated. The phantom unit awards are common stock equivalents and are included in our dilutive earnings per unit calculation.

(2) Awards that vest only upon the achievement of the distribution rate performance criteria and the date indicated. In addition, the awards will be forfeited if the performance criteria are not met in six years. These awards are not common stock equivalents and are not included in our dilutive earnings per unit calculation.

Compensation expense is recognized ratably over time for the phantom units and DERs that vest based on the passage of time. To the extent that the vesting of the awards or DERs is accelerated, the

related compensation expense will also be accelerated. For those phantom units and DERs that vest upon the achievement of performance criteria, expense is recognized when it is considered probable the criteria will be achieved.

In addition to the phantom units discussed above, four of our non-employee directors each have received LTIP awards of 5,000 units in the aggregate. These awards vest yearly in 25% increments (1,250 units). The awards have an automatic re-grant feature such that as they vest, a similar amount is granted. For the other two non-employee directors, any director compensation is assigned to the entity that designated them as directors. In those cases, no LTIP award was granted, but a cash payment is made.

We have concluded that it is probable that we will achieve a $2.60 annualized distribution rate and therefore have accelerated the vesting of the portion of the awards that vest based on that rate. We recognized total compensation expense of approximately $2.2 million in the first quarter of 2005 related to the awards granted under our 1998 LTIP and our 2005 LTIP.

Note 8 Derivative Instruments and Hedging Activities

We utilize various derivative instruments to (i) manage our exposure to commodity price risk, (ii) engage in a controlled trading program, (iii) manage our exposure to interest rate risk and (iv) manage our exposure to currency exchange rate risk. Our risk management policies and procedures are designed to monitor interest rates, currency exchange rates, NYMEX and over-the-counter positions, as well as physical volumes, grades, locations and delivery schedules, to ensure that our hedging activities address our market risks. We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategy for undertaking the hedge. We calculate hedge effectiveness on a quarterly basis. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument's effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items.

Summary of Financial Impact

The majority of our derivative activity is related to our commodity price risk hedging activities. Through these activities we hedge our exposure to price fluctuations with respect to crude oil and LPG in storage, and expected purchases, sales and transportation of these commodities. The derivative instruments we use consist primarily of futures and options contracts traded on the NYMEX and over-the-counter transactions, including crude oil swap and option contracts entered into with financial institutions and other energy companies.

The majority of the instruments that qualify for hedge accounting are cash flow hedges. Therefore, the corresponding changes in fair value for the effective portion of the hedges are deferred to Accumulated Other Comprehensive Income ("OCI") and recognized in revenues or crude oil and LPG purchases and related costs in the periods during which the underlying physical transactions occur. Derivatives that do not qualify for hedge accounting and the portion of cash flow hedges that is not highly effective (as defined in Statement of Financial Accounting Standard No. 133) in offsetting changes in cash flows of hedged items are marked-to-market in revenues each period.

During the first quarter of 2005, our earnings include a net gain of approximately $35.5 million resulting from all derivative activities, including the change in fair value of open derivatives and settled derivatives taken to earnings during the quarter. This gain includes:

a) a net mark-to-market loss of $13.4 million, which is comprised of:

- the net change in fair value during the quarter of open derivatives used to hedge price exposure that do not qualify for hedge accounting (a loss of approximately $12.7 million) and

- the net change in fair value during the quarter of the portion of cash flow hedges related to open derivatives that is not highly effective in offsetting changes in cash flows of hedged items (a loss of approximately $0.7 million).

b) a net gain of $48.9 million related to settled derivatives taken to earnings during the period. The majority of this net gain is related to cash flow hedges that were recognized in earnings in conjunction with the underlying physical transactions that occurred during the first quarter of 2005.

The following table summarizes the net assets and liabilities related to the fair value of our open derivative positions on our consolidated balance sheet as of March 31, 2005:

Other current assets	$ 21.6
Other long-term assets	9.6
Other current-liabilities	(65.8)
Other long-term liabilities and deferred credits	(12.2)

The net liability as of March 31, 2005, relates mostly to unrealized losses on effective cash flow hedges that are deferred to OCI. At March 31, 2005, there is a total unrealized net loss of approximately $41.4 million deferred to OCI. This includes $35.7 million, which predominantly relates to unrealized losses on derivatives used to hedge physical inventory in storage that receive hedge accounting, and $5.7 million relating to terminated interest rate swaps, which are being amortized to interest expense over the original terms of the terminated instruments. The inventory hedges are mostly short derivative positions that will result in losses when prices rise. These hedge losses are offset by an increase in the physical inventory value and will be reclassed into earnings from OCI in the same period that the underlying physical inventory is sold. The total amount of deferred net losses recorded in OCI are expected to be reclassified to future earnings, contemporaneously with the related physical purchase or delivery of the underlying commodity or payments of interest.

Of the total net loss deferred in OCI at March 31, 2005, a net loss of $36.0 million will be reclassified into earnings in the next twelve months and the remaining net loss at various intervals (ending in 2016 for amounts related to our terminated interest rate swaps and 2009 for amounts related to our commodity price-risk hedging). Because a portion of these amounts is based on market prices at the current period end, actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

During the three months ended March 31, 2005, no amounts were reclassified to earnings from OCI in connection with forecasted transactions that were no longer considered probable of occurring.

Note 9 Commitments and Contingencies

Litigation

Export License Matter. In our gathering and marketing activities, we import and export crude oil from and to Canada. Exports of crude oil are subject to the "short supply" controls of the Export Administration Regulations ("EAR") and must be licensed by the Bureau of Industry and Security (the

"BIS") of the U.S. Commerce Department. In 2002, we determined that we may have violated the terms of our licenses with respect to the quantity of crude oil exported and the end-users in Canada. Export of crude oil except as authorized by license is a violation of the EAR. In October 2002, we submitted to the BIS an initial notification of voluntary disclosure. The BIS subsequently informed us that we could continue to export while previous exports were under review. We applied for and received several new licenses allowing for export volumes and end users that more accurately reflect our anticipated business and customer needs. We also conducted reviews of new and existing contracts and implemented new procedures and practices in order to monitor compliance with applicable laws regarding the export of crude oil to Canada. As a result, we subsequently submitted additional information to the BIS in October 2003 and May 2004. In August 2004, we received a request from the BIS for additional information. We have responded to this and subsequent requests, and continue to cooperate fully with BIS officials. At this time, we have received neither a warning letter nor a charging letter, which could involve the imposition of penalties, and no indication of what penalties the BIS might assess. As a result, we cannot reasonably estimate the ultimate impact of this matter.

Alfons Sperber v. Plains Resources Inc., et al. On December 18, 2003, a putative class action lawsuit was filed in the Delaware Chancery Court, New Castle County, entitled Alfons Sperber v. Plains Resources Inc., et al. This suit, brought on behalf of a putative class of Plains All American Pipeline, L.P. common unitholders, asserted breach of fiduciary duty and breach of contract claims against us, Plains AAP, L.P., and Plains All American GP LLC and its directors, as well as breach of fiduciary duty claims against Plains Resources Inc. and its directors (Plains Resources, Inc. is a unitholder and an interest owner in our general partner). The complaint sought to enjoin or rescind a proposed acquisition of all of the outstanding stock of Plains Resources Inc., as well as declaratory relief, an accounting, disgorgement and the imposition of a constructive trust, and an award of damages, fees, expenses and costs, among other things. This lawsuit has been settled in principle. The court has approved the settlement and the settlement became final in March 2005.

Pipeline Releases. In December 2004 and January 2005, we experienced two unrelated releases of crude oil that reached rivers located near the sites where the releases originated. In late December 2004, one of our pipelines in West Texas experienced a rupture that resulted in the release of approximately 4,500 barrels of crude oil, a portion of which reached a remote location of the Pecos River. In early January 2005, an overflow from a temporary storage tank located in East Texas resulted in the release of approximately 1,200 barrels of crude oil, a portion of which reached the Sabine River. In both cases, emergency response personnel under the supervision of a unified command structure consisting of representatives of Plains Pipeline, the U.S. Environmental Protection Agency, the Texas Commission on Environmental Quality and the Texas Railroad Commission conducted clean-up operations at each site. Approximately 4,200 barrels and 980 barrels were recovered from the two respective sites. The unrecovered oil has been or will be removed or otherwise addressed by PAA in the course of site remediation. Aggregate costs associated with the releases, including estimated remediation costs, are estimated to be approximately $3.0 million to $3.5 million. We continue to work with the appropriate state and federal environmental authorities in responding to the releases and no enforcement proceedings have been instituted by any governmental authority at this time.

General. We, in the ordinary course of business, are a claimant and/or a defendant in various legal proceedings. We do not believe that the outcome of these legal proceedings, individually or in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows.

Environmental

We may experience future releases of crude oil into the environment from our pipeline and storage operations, or discover past releases that were previously unidentified. Although we maintain an inspection program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to any such environmental releases from our assets may substantially affect our business. At March 31, 2005, our reserve for environmental liabilities totaled approximately $23.3 million. Approximately $16.3 million of the reserve is related to liabilities assumed as part of the Link acquisition. Although we believe our reserve is adequate, no assurance can be given that any costs incurred in excess of this reserve would not have a material adverse effect on our financial condition, results of operations or cash flows.

Other

A pipeline, terminal or other facility may experience damage as a result of an accident or natural disaster. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance of various types that we consider adequate to cover our operations and properties. The insurance covers our assets in amounts considered reasonable. The insurance policies are subject to deductibles that we consider reasonable and not excessive. Our insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues. The overall trend in the environmental insurance industry appears to be a contraction in the breadth and depth of available coverage, while costs, deductibles and retention levels have increased. Absent a material favorable change in the insurance markets, this trend is expected to continue as we continue to grow and expand. As a result, we anticipate that we will elect to self-insure more of our activities or incorporate higher retention in our insurance arrangements.

The occurrence of a significant event not fully insured, indemnified or reserved against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe we are adequately insured for public liability and property damage to others with respect to our operations. We believe that our levels of coverage and retention are generally consistent with those of similarly situated companies in our industry. With respect to all of our coverage, no assurance can be given that we will be able to maintain adequate insurance in the future at rates we consider reasonable, or that we have established adequate reserves to the extent that such risks are not insured.

Note 10 Operating Segments

Our operations consist of two operating segments: (i) pipeline transportation operations ("Pipeline Operations") and (ii) gathering, marketing, terminalling and storage operations ("GMT&S"). Through our pipeline segment, we engage in interstate and intrastate crude oil pipeline transportation and certain related margin activities. Through our GMT&S segment, we engage in purchases and resales of crude oil and LPG at various points along the distribution chain and we operate certain terminalling and storage assets. We believe that the combination of our terminalling and storage activities and gathering and marketing activities provides a counter-cyclical balance that has a stabilizing effect on our results of operations and cash flow. In a contango market (oil prices for future deliveries are higher than for current deliveries), we use our tankage to improve our gathering margins by storing crude oil we have purchased at lower prices in the current month for delivery at higher prices in future months. In a backwardated market (oil prices for future deliveries are lower than for current deliveries), we use and lease less storage capacity, but increased marketing margins (premiums for prompt delivery) provide an offset to this reduced cash flow.

We evaluate segment performance based on segment profit and maintenance capital. We define segment profit as revenues less (i) purchases, (ii) field operating costs, and (iii) segment general and administrative expenses. Maintenance capital consists of capital expenditures required either to maintain the existing operating capacity of partially or fully depreciated assets or to extend their useful lives. Capital expenditures made to expand our existing capacity, whether through construction or acquisition, are not considered maintenance capital expenditures. Repair and maintenance expenditures associated with existing assets that do not extend the useful life or expand the operating capacity are charged to expense as incurred. The following table reflects certain financial data for each segment for the periods indicated (note that each of the items in the following table excludes depreciation and amortization):

	Pipeline	GMT&S	Total
		(in millions)	
Three Months Ended March 31, 2005			
Revenues:			
External Customers (includes buy/sell revenues in our Pipeline and GMT&S segments of $33.5 and $3,419.0, respectively)[2]	$ 212.5	$ 6,426.0	$ 6,638.5
Intersegment[1]	34.7	0.2	34.9
Total revenues of reportable segments	$ 247.2	$ 6,426.2	$ 6,673.4
Segment profit[2]	$ 50.1	$ 16.3	$ 66.4
SFAS 133 noncash mark-to-market adjustment[2]	$	$ (13.4)	$ (13.4)
Maintenance capital	$ 2.8	$ 1.2	$ 4.0
Three Months Ended March 31, 2004			
Revenues:			
External Customers (includes buy/sell revenues in our Pipeline and GMT&S segments of $46.4 and $1,834.9, respectively)[2]	$ 173.5	$ 3,631.1	$ 3,804.6
Intersegment[1]	15.8	0.2	16.0
Total revenues of reportable segments	$ 189.3	$ 3,631.3	$ 3,820.6
Segment profit[2]	$ 25.5	$ 28.1	$ 53.6
SFAS 133 noncash mark-to-market adjustment[2]	$	$ 7.5	$ 7.5
Maintenance capital	$ 1.4	$ 0.3	$ 1.7

(1) Intersegment sales are conducted at arms length.

(2) Amounts related to SFAS 133 are included in revenues and impact segment profit.

(3) The following table reconciles segment profit to consolidated income before cumulative effect of change in accounting principle:

	For the three months ended March 31,	
	2005	2004

	For the three months ended March 31,	
	(in millions)	
Segment profit	$ 66.4	$ 53.6
Depreciation and amortization	(19.1)	(13.1)
Interest expense	(14.6)	(9.5)
Interest and other income (expense), net	0.1	
Income before cumulative effect of change in accounting principle	$ 32.8	$ 31.0

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Plains All American Pipeline, L.P.'s management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

Management has used the framework set forth in the report entitled "Internal Control Integrated Framework" published by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") to evaluate the effectiveness of the Company's internal control over financial reporting. Based on that evaluation, management has concluded that the Company's internal control over financial reporting was effective as of December 31, 2004. Our management's assessment of the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2004 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

/s/ GREG L. ARMSTRONG

Greg L. Armstrong, Chairman of the Board, Chief Executive Officer and Director of Plains All American GP LLC (Principal Executive Officer)

/s/ PHILLIP D. KRAMER

Phillip D. Kramer, Executive Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial Officer)
March 2, 2005

Report of Independent Registered Public Accounting Firm

To the Board of Directors of the General Partner and Unitholders of
Plains All American Pipeline, L.P.:

We have completed an integrated audit of Plains All American Pipeline, L.P.'s 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and audits of its 2003 and 2002 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of cash flows, of changes in partners' capital, of comprehensive income and of changes in accumulated other comprehensive income (loss) present fairly, in all material respects, the financial position of Plains All American Pipeline, L.P. and its subsidiaries at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, the Partnership changed its method of accounting for pipeline linefill in third party assets effective January 1, 2004.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that the Partnership maintained effective internal control over financial reporting as of December 31, 2004 based on criteria established in COSO, is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control Integrated Framework issued by the COSO. The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Partnership's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP

Houston, Texas
March 2, 2005

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands, except unit data)

	December 31, 2004	December 31, 2003
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 12,988	$ 4,137
Trade accounts receivable, net	521,785	590,645
Inventory	498,200	105,967
Other current assets	68,229	32,225
Total current assets	1,101,202	732,974
PROPERTY AND EQUIPMENT	1,911,509	1,272,634
Accumulated depreciation	(183,887)	(121,595)
	1,727,622	1,151,039
OTHER ASSETS		
Pipeline linefill in owned assets	168,352	95,928
Inventory in third party assets	59,279	26,725
Other, net	103,956	88,965
Total assets	$ 3,160,411	$ 2,095,631
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable	$ 850,912	$ 603,460
Due to related parties	32,897	26,981
Short-term debt	175,472	127,259
Other current liabilities	54,436	44,219
Total current liabilities	1,113,717	801,919
LONG-TERM LIABILITIES		
Long-term debt under credit facilities and other	151,753	70,000
Senior notes, net of unamortized discount of $2,729 and $1,009, respectively	797,271	448,991
Other long-term liabilities and deferred credits	27,466	27,994
Total liabilities	2,090,207	1,348,904
COMMITMENTS AND CONTINGENCIES (NOTES 11 and 12)		
PARTNERS' CAPITAL		

	December 31, 2004	December 31, 2003
Common unitholders (62,740,218 and 49,502,556 units outstanding at December 31, 2004, and December 31, 2003, respectively)	919,826	744,073
Class B common unitholder (1,307,190 units outstanding at each date)	18,775	18,046
Class C common unitholders (3,245,700 units and no units outstanding at December 31, 2004, and December 31, 2003, respectively)	100,423	
Subordinated unitholders (no units and 7,522,214 units outstanding at December 31, 2004, and December 31, 2003, respectively)		(39,913)
General partner	31,180	24,521
Total partners' capital	1,070,204	746,727
Total liabilities and partners' capital	$ 3,160,411	$ 2,095,631

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

	Twelve Months Ended December 31,		
	2004	**2003**	**2002**
REVENUES			
Crude oil and LPG sales (includes approximately $11,246,951, $6,124,895 and $4,140,830, respectively, related to buy/sell transactions, see Note 2)	$ 20,184,319	$ 11,952,623	$ 7,892,405
Other gathering, marketing, terminalling and storage revenues	38,310	32,052	29,366
Pipeline margin activities revenues (includes approximately $149,797, $166,165 and $95,826, respectively, related to buy/sell transactions, see Note 2)	575,222	505,287	382,513
Pipeline tariff activities revenues	177,619	99,887	79,939
Total revenues	20,975,470	12,589,849	8,384,223
COSTS AND EXPENSES			
Crude oil and LPG purchases and related costs (includes approximately $11,137,669, $5,967,165 and $4,026,245, respectively, related to buy/sell transactions, see Note 2)	19,870,865	11,746,382	7,741,185
Pipeline margin activities purchases (includes approximately $142,538, $159,231 and $87,554, respectively, related to buy/sell transactions, see Note 2)	553,707	486,154	362,311
Field operating costs (excluding LTIP charge)	218,548	134,177	106,436
LTIP charge operations	918	5,727	
General and administrative expenses (excluding LTIP charge)	75,735	49,969	45,663
LTIP charge general and administrative	7,013	23,063	
Depreciation and amortization	67,241	46,821	34,068
Total costs and expenses	20,794,027	12,492,293	8,289,663
Gain on sales of assets	580	648	
Asset impairment	(2,000)		
OPERATING INCOME	180,023	98,204	94,560
OTHER INCOME/(EXPENSE)			
Interest expense (net of capitalized interest of $544, $524 and $773)	(46,676)	(35,226)	(29,057)
Interest and other income (expense), net	(211)	(3,530)	(211)
Income before cumulative effect of change in accounting principle	133,136	59,448	65,292
Cumulative effect of change in accounting principle	(3,130)		
NET INCOME	$ 130,006	$ 59,448	$ 65,292
NET INCOME-LIMITED PARTNERS	$ 119,286	$ 53,473	$ 60,912

	Twelve Months Ended December 31,		
NET INCOME-GENERAL PARTNER	$ 10,720	$ 5,975	$ 4,380
BASIC NET INCOME PER LIMITED PARTNER UNIT			
Income before cumulative effect of change in accounting principle	$ 1.94	$ 1.01	$ 1.34
Cumulative effect of change in accounting principle	(0.05)		
Basic net income per limited partner unit	$ 1.89	$ 1.01	$ 1.34
DILUTED NET INCOME PER LIMITED PARTNER UNIT			
Income before cumulative effect of change in accounting principle	$ 1.94	$ 1.00	$ 1.34
Cumulative effect of change in accounting principle	(0.05)		
Diluted net income per limited partner unit	$ 1.89	$ 1.00	$ 1.34
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	63,277	52,743	45,546
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	63,277	53,400	45,546

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended December 31,		
	2004	**2003**	**2002**
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 130,006	$ 59,448	$ 65,292
Adjustments to reconcile to cash flows from operating activities:			
Depreciation and amortization	67,241	46,821	34,068
Gain on sales of assets	(580)	(648)	
Cumulative effect of change in accounting principle	3,130		
Allowance for doubtful accounts	400	360	146
Inventory valuation adjustment	2,032		
SFAS 133 non-cash mark-to-market adjustment	(994)	(363)	(243)
Gain on foreign currency revaluation	(4,954)		
Non-cash amortization of terminated interest rate swap	1,486		
Net cash paid for terminated swaps	(1,465)	(6,152)	
Loss on refinancing of debt	658	3,272	
LTIP charge	7,931	28,790	
Impairment of long-lived assets	2,000		
Changes in assets and liabilities, net of acquisitions:			
Trade accounts receivable and other assets	(30,364)	(102,005)	(136,480)
Inventory	(398,671)	(38,941)	105,944
Accounts payable and other liabilities	327,449	121,274	107,265
Inventory in third-party assets	(7,248)		
Due to related parties	5,911	3,452	8,962
Net cash provided by operating activities	103,968	115,308	184,954
CASH FLOWS FROM INVESTING ACTIVITIES			
Cash paid in connection with acquisitions (Note 3)	(535,266)	(168,359)	(324,628)
Additions to property and equipment	(116,944)	(65,416)	(40,590)
Cash paid for linefill on assets owned	(1,989)	(46,790)	(11,060)
Proceeds from sales of assets	3,012	8,450	1,437
Net cash used in investing activities	(651,187)	(272,115)	(374,841)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net borrowings/(repayments) on long-term revolving credit facilities and other	64,893	62,473	(42,144)
Net borrowings on working capital revolving credit facility	62,900	25,300	
Net repayments on short-term letter of credit and hedged inventory facilities	(20,090)	(6,197)	(4,770)
Principal payments on senior secured term loans		(297,000)	(3,000)
Cash paid in connection with financing arrangements	(5,073)	(5,191)	(5,435)
Net proceeds from the issuance of common units (Note 6)	262,132	250,341	145,046
Proceeds from the issuance of senior notes	348,068	249,340	199,600
Distributions paid to unitholders and general partner	(158,352)	(121,822)	(99,841)
Net cash provided by financing activities	554,478	157,244	189,456

	Year Ended December 31,		
Effect of translation adjustment on cash	1,592	199	421
Net increase (decrease) in cash and cash equivalents	8,851	636	(10)
Cash and cash equivalents, beginning of period	4,137	3,501	3,511
Cash and cash equivalents, end of period	$ 12,988	$ 4,137	$ 3,501
Cash paid for interest, net of amounts capitalized	$ 40,780	$ 36,382	$ 28,550

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF CHANGES IN PARTNERS' CAPITAL
(in thousands)

	Common Units		Class B Common Units		Class C Common Units		Subordinated Units		General Partner	Total	Total Partners' Capital
	Units	Amount	Units	Amount	Units	Amount	Units	Amount	Amount	Units	Amount
					(unaudited)						
Balance at December 31, 2001	31,916	$ 408,562	1,307	$ 19,534		$	10,030	$ (38,891)	$ 13,592	43,253	$ 402,797
Issuance of common units	6,325	142,013							3,033	6,325	145,046
Net income		45,857		1,736				13,319	4,380		65,292
Distributions		(70,821)		(2,762)				(21,188)	(5,070)		(99,841)
Other comprehensive loss		(1,183)		(45)				(343)	(113)		(1,684)
Balance at December 31, 2002	38,241	$ 524,428	1,307	$ 18,463		$	10,030	$ (47,103)	$ 15,822	49,578	$ 511,610
Issuance of common units	8,736	245,093							5,237	8,736	250,330
Issuance of common units under LTIP	18	555							11	18	566
Net income		41,278		1,370				10,825	5,975		59,448
Conversion of subordinated units	2,507	(9,823)					(2,507)	9,823			
Distributions		(89,801)		(2,860)				(21,939)	(7,222)		(121,822)
Other comprehensive income		32,343		1,073				8,481	4,698		46,595
Balance at December 31, 2003	49,502	$ 744,073	1,307	$ 18,046		$	7,523	$ (39,913)	$ 24,521	58,332	$ 746,727
Issuance of common units	4,968	157,568							3,371	4,968	160,939
Issuance of common units under LTIP	362	11,772							238	362	12,010
Private placement of Class C common units					3,246	98,782			2,041	3,246	100,823
Issuance of units for acquisition contingent consideration	385	13,082							267	385	13,349
Distributions		(134,175)		(3,009)		(5,648)		(4,231)	(11,289)		(158,352)

			Class B Common Units		**Class C Common Units**						
Other comprehensive income		59,886		1,248		3,098		(841)	1,311		64,702
Net income		111,161		2,490		4,191		1,444	10,720		130,006
Conversion of subordinated units	7,523	(43,541)					(7,523)	43,541			
Balance at December 31, 2004	62,740	$ 919,826	1,307	$ 18,775	3,246	$ 100,423		$	$ 31,180	67,293	$ 1,070,204

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2004	2003	2002
		(in thousands)	
Net income	$ 130,006	$ 59,448	$ 65,292
Other comprehensive income (loss)	64,702	46,595	(1,684)
Comprehensive income	$ 194,708	$ 106,043	$ 63,608

CONSOLIDATED STATEMENT OF CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	Net Deferred Gain/(Loss) on Derivative Instruments	Currency Translation Adjustments	Total
		(in thousands)	
Balance at December 31, 2001	$ (4,740)	$ (8,002)	$ (12,742)
Reclassification adjustments for settled contracts	797		797
Changes in fair value of outstanding hedge positions	(4,264)		(4,264)
Currency translation adjustment		1,783	1,783
2002 Activity	(3,467)	1,783	(1,684)
Balance at December 31, 2002	(8,207)	(6,219)	(14,426)
Reclassification adjustments for settled contracts	(28,151)		(28,151)
Changes in fair value of outstanding hedge positions	28,666		28,666
Currency translation adjustment		46,080	46,080
2003 Activity	515	46,080	46,595
Balance at December 31, 2003	(7,692)	39,861	32,169
Reclassification adjustments for settled contracts	13,262		13,262
Changes in fair value of outstanding hedge positions	20,367		20,367
Currency translation adjustment		31,073	31,073
2004 Activity	33,629	31,073	64,702
Balance at December 31, 2004	$ 25,937	$ 70,934	$ 96,871

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1 Organization and Basis of Presentation

Organization

Plains All American Pipeline, L.P. ("PAA") is a Delaware limited partnership formed in September of 1998. Our operations are conducted directly and indirectly through our operating subsidiaries, Plains Marketing, L.P., Plains Pipeline, L.P. and Plains Marketing Canada, L.P. We are engaged in interstate and intrastate crude oil transportation, and crude oil gathering, marketing, terminalling and storage, as well as the marketing and storage of liquefied petroleum gas and other natural gas related petroleum products. We refer to liquified petroleum gas and natural gas related petroleum products collectively as "LPG." We own an extensive network of pipeline transportation, terminalling, storage and gathering assets in key oil producing basins and at major market hubs in the United States and Canada.

Our 2% general partner interest is held by Plains AAP, L.P., a Delaware limited partnership. Plains All American GP LLC, a Delaware limited liability company, is Plains AAP, L.P.'s general partner. Plains All American GP LLC manages our operations and activities and employs our officers and personnel, who devote 100% of their efforts to the management of the Partnership. Unless the context otherwise requires, we use the term "general partner" to refer to both Plains AAP, L.P. and Plains All American GP LLC. Plains AAP, L.P. and Plains All American GP LLC are essentially held by seven owners with interests ranging from 44% to 3.2%.

Basis of Consolidation and Presentation

The accompanying financial statements and related notes present our consolidated financial position as of December 31, 2004 and 2003, and the consolidated results of our operations, cash flows, changes in partners' capital, comprehensive income (loss) and changes in accumulated other comprehensive income for the years ended December 31, 2004, 2003 and 2002. All significant intercompany transactions have been eliminated. Certain reclassifications were made to prior periods to conform with the current period presentation. The accompanying consolidated financial statements of PAA include PAA and all of its wholly-owned subsidiaries. Investments in 50% or less owned affiliates, over which the Company has significant influence, are accounted for by the equity method.

Change in Accounting Principle

During the second quarter of 2004, we changed our method of accounting for pipeline linefill in third party assets. Historically, we have viewed pipeline linefill, whether in our assets or third party assets, as having long-term characteristics rather than characteristics typically associated with the short-term classification of operating inventory. Therefore, previously we have not included linefill barrels in the same average costing calculation as our operating inventory, but instead have carried linefill at historical cost. Following this change in accounting principle, the linefill in third party assets that we have historically classified as a portion of "Pipeline Linefill" on the face of the balance sheet (a long-term asset) and carried at historical cost, is included in "Inventory" (a current asset) in determining the average cost of operating inventory and applying the lower of cost or market analysis. At the end of each period, we reclassify the linefill in third party assets not expected to be liquidated within the succeeding twelve months out of "Inventory" (a current asset), at average cost, and into "Inventory in Third Party Assets" (a long-term asset), which is now reflected as a separate line item within other assets on the consolidated balance sheet.

This change in accounting principle is effective January 1, 2004 and is reflected in the consolidated statement of operations for the year ended December 31, 2004 and the consolidated balance sheets as of December 31, 2004 and 2003 included herein. The cumulative effect of this change in accounting principle as of January 1, 2004, is a charge of approximately $3.1 million, representing a reduction in Inventory of approximately $1.7 million, a reduction in Pipeline Linefill of approximately $30.3 million and an increase in Inventory in Third Party Assets of $28.9 million. The pro forma impact for the year ended December 31, 2003 would have been an increase to net income of approximately $2.0 million ($0.04 per basic and diluted limited partner unit) resulting in pro forma net income of $61.5 million and pro forma basic net income per limited partner unit of $1.05 and pro forma diluted net income per limited partner unit of $1.04. The pro forma impact for the year ended December 31, 2002 would have been a decrease to net income of approximately $0.1 million (no impact to basic and diluted limited partner unit) resulting in pro forma net income of $65.2 million and pro forma basic net income per limited partner unit of $1.34 and pro forma diluted net income per limited partner unit of $1.34.

In conjunction with this change in accounting principle, we have classified cash flows associated with purchases and sales of linefill on assets that we own as cash flows from investing activities instead of the historical classification of cash flows from operating activities. As a result of this change in classification, net cash provided by operating activities for the years ended December 31, 2003 and 2002 increased to $115.3 million from $68.5 million and to $185.0 million from $173.9 million, respectively. Net cash used in investing activities for the years ended December 31, 2003 and 2002 increased to $272.1 million from $225.3 million and $374.8 million from $363.8 million, respectively.

Note 2 Summary of Significant Accounting Policies

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates we make include: (i) accruals related to purchases and sales, (ii) mark-to-market estimates pursuant to Statement of Financial Accounting Standards ("SFAS") No. 133 "Accounting For Derivative Instruments and Hedging Activities", as amended, (iii) contingent liability accruals and (iv) estimated fair value of assets and liabilities acquired and identification of associated goodwill and intangible assets. Although we believe these estimates are reasonable, actual results could differ from these estimates.

Revenue Recognition

Buy/sell transactions. The Emerging Issues Task Force ("EITF") is currently considering Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty," ("EITF No. 04-13"), which relates to buy/sell transactions. The issues to be addressed by the EITF are i) under what circumstances should two or more transactions with the same counterparty be viewed as a single nonmonetary transaction within the scope of APB No. 29; and ii) if nonmonetary transactions within the scope of APB No. 29 involve inventory, are there any circumstances under which the transactions should be recognized at fair value.

Buy/sell transactions are contractual arrangements in which we agree to buy a specific quantity and quality of crude oil or LPG to be delivered at a specific location while simultaneously agreeing to sell a specified quantity and quality of crude oil or LPG at a different location, usually with the same counterparty. These arrangements are generally designed to increase our margin through a variety of methods, including reducing our transportation or storage costs or acquiring a grade of crude oil that more closely matches our physical delivery requirement to one of our other customers. The value difference between purchases and sales is referred to as margin and is primarily due to grade, quality or location differentials. All buy/sell transactions result in us making or receiving physical delivery of the product, involve the attendant risks and rewards of ownership, including title transfer, assumption of environmental risk, transportation scheduling, credit risk and counterparty nonperformance risk, and such transactions are settled in cash similar to all other purchases and sales. Accordingly, such transactions are recorded in both revenues and purchases as separate sales and purchase transactions on a "gross" basis.

We believe that buy/sell transactions are monetary in nature and thus outside the scope of APB Opinion No. 29, "Accounting for Nonmonetary Transactions" ("APB No. 29"). Additionally, we have evaluated EITF No. 99-19, "Reporting Revenue Gross as a Principal versus Net as an Agent" ("EITF No. 99-19") and, based on that evaluation, we believe that recording these transactions on a gross basis is appropriate. If the EITF were to determine that these transactions should be accounted for as monetary transactions on a gross basis, no change in our accounting policy for buy/sell transactions would be necessary. If the EITF were to determine that these transactions should be accounted for as nonmonetary transactions qualifying for fair value recognition and require a net presentation of such transactions, the amounts of revenues and purchases associated with buy/sell transactions would be netted in our consolidated statement of operations, but there would be no effect on operating income, net income or cash flows from operating activities. If the EITF were to determine that these transactions should be accounted for as nonmonetary transactions not qualifying for fair value recognition, these amounts of revenues and purchases would be netted in our consolidated statement of operations and there could be an impact on operating income and net income related to the timing of the ultimate sale of product purchased in the "buy" side of the buy/sell transaction. However, we do not believe any impact on operating income, net income or cash flows from operating activities would be material.

Gathering, Marketing, Terminalling and Storage Segment Revenues. Revenues from crude oil and LPG sales are recognized at the time title to the product sold transfers to the purchaser, which occurs upon receipt of the product by the purchaser. Sales of crude oil and LPG consist of outright sales contracts and buy/sell arrangements which are booked gross as well as barrel exchanges which are booked net.

Terminalling and storage revenues, which are classified as other revenues on the income statement, consist of (i) storage fees from actual storage used on a month-to-month basis; (ii) storage fees resulting from short-term and long-term contracts for committed space that may or may not be utilized by the customer on a given month; and (iii) terminal throughput charges to pump crude oil to connecting carriers. Revenues on storage are recognized ratably over the term of the contract. Terminal throughput charges are recognized as the crude oil exits the terminal and is delivered to the connecting crude oil carrier. Any throughput volumes in transit at the end of a given month are treated as third party inventory and do not incur storage fees. All terminalling and storage revenues are based on actual volumes and rates.

Pipeline Segment Revenues. Pipeline margin activities primarily consist of the purchase and sale of crude oil shipped on our San Joaquin Valley system from barrel exchanges and buy/sell arrangements. Revenues associated with these activities are recognized at the time title to the product sold transfers to the purchaser, which occurs upon receipt of the product by the purchaser. Revenues for these transactions are recorded gross except in the case of barrel exchanges that are net settled. All of our pipeline margin activities revenues are based on actual volumes and prices. Revenues from pipeline tariffs and fees are associated with the transportation of crude oil at a published tariff as well as fees associated with line leases for committed space on a particular system that may or may not be utilized. Tariff revenues are recognized either at the point of delivery or at the point of receipt pursuant to specifications outlined in the regulated and non-regulated tariffs. Revenues associated with line lease fees are recognized in the month to which the lease applies, whether or not the space is actually utilized. All pipeline tariff and fee revenues are based on actual volumes and rates.

Purchases and Related Costs

Purchases and related costs include: (i) the cost of crude oil and LPG purchased in outright purchases as well as buy/sell arrangements; (ii) third party transportation and storage, whether by pipeline, truck or barge; and (iii) expenses to issue letters of credit to support these purchases. These purchases are accrued at the time title transfers to us which occurs upon receipt of the product.

Operating Expenses and General and Administrative Expenses

Operating expenses consist of various field and pipeline operating expenses including fuel and power costs, telecommunications, labor costs for truck drivers and pipeline field personnel, maintenance costs, regulatory compliance, environmental remediation, insurance, vehicle leases, and property taxes. General and administrative expenses consist primarily of payroll and benefit costs, certain information system and legal costs, office rent, contract and consultant costs, and audit and tax fees.

Foreign Currency Transactions

Assets and liabilities of subsidiaries with a functional currency other than the U.S. Dollar are translated at period end rates of exchange and revenues and expenses are translated at average exchange rates prevailing for each month. The resulting translation adjustments are made directly to a separate component of other comprehensive income in partners' capital. Gains and losses from foreign currency transactions (transactions denominated in a currency other than the entity's functional currency) are included in the consolidated statement of operations. These gains totaled approximately $5.0 million for the year ended December 31, 2004, and were immaterial for the years ended December 31, 2003 and 2002.

Cash and Cash Equivalents

Cash and cash equivalents consist of all demand deposits and funds invested in highly liquid instruments with original maturities of three months or less and typically exceed federally insured limits. We periodically assess the financial condition of the institutions where these funds are held and believe that any possible credit risk is minimal.

Accounts Receivable

Our accounts receivable are primarily from purchasers and shippers of crude oil and, to a lesser extent, purchasers of LPG. There was a nominal amount due from related parties at December 31, 2004 and no amounts due from related parties at December 31, 2003. The majority of our accounts receivable relate to our gathering and marketing activities that can generally be described as high volume and low margin activities, in many cases involving complex exchanges of crude oil volumes. We make a determination of the amount, if any, of the line of credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial assurances are commonly provided to us in the form of standby letters of credit, advance cash payments or "parental" guarantees. At December 31, 2004, we had received approximately $20.3 million of advance cash payments and prepayments from third parties to mitigate credit risk. In addition, we enter into netting arrangements with our counterparties. These arrangements cover a significant part of our transactions and also serve to mitigate credit risk.

We review all outstanding accounts receivable balances on a monthly basis and assess whether our allowance for doubtful trade accounts receivable is adequate. Actual balances are not applied against the reserve until all collection efforts have been exhausted. At December 31, 2004 and 2003, substantially all of our net accounts receivable classified as current were less than 60 days past their scheduled invoice date, and our allowance for doubtful accounts receivable (the entire balance of which is classified as current) totaled $0.6 million and $0.2 million, respectively. Although we consider our allowance for doubtful trade accounts receivable to be adequate, there is no assurance that actual amounts will not vary significantly from estimated amounts. Following is a reconciliation of the changes in our allowance for doubtful accounts balances (in millions):

	December 31,		
	2004	**2003**	**2002**
Balance at beginning of year	$ 0.2	$ 8.1	$ 8.0
Applied to accounts receivable balances		(8.3)	
Increase in reserve charged to expense	0.4	0.4	0.1
Balance at end of year	$ 0.6	$ 0.2	$ 8.1

Inventory and Pipeline Linefill

Inventory primarily consists of crude oil and LPG in pipelines, storage tanks and rail cars that is valued at the lower of cost or market, with cost determined using an average cost method. During the fourth quarter of 2004, we recorded a $2.0 million noncash charge related to the writedown of our LPG inventory. Linefill and minimum working inventory requirements are recorded at historical cost and consist of crude oil and LPG used to pack an operated pipeline such that when an incremental barrel enters a pipeline it forces a barrel out at another location, as well as the minimum amount of crude oil necessary to operate our storage and terminalling facilities.

Linefill and minimum working inventory requirements in third party assets are included in "Inventory" (a current asset) in determining the average cost of operating inventory and applying the lower of cost or market analysis. At the end of each period, we reclassify the linefill in third party assets not expected to be liquidated within the succeeding twelve months out of "Inventory," at average cost, and into "Inventory in Third Party Assets" (a long-term asset), which is reflected as a separate line item within other assets on the consolidated balance sheet.

At December 31, 2004 and 2003, inventory and linefill consisted of:

	December 31, 2004			December 31, 2003		
	Barrels	Dollars	Dollar/ barrel	Barrels	Dollars	Dollar/ barrel
	(Barrels in thousands and dollars in millions)					
Inventory						
Crude oil	8,716	$ 396.2	$ 45.46	1,676	$ 50.6	$ 30.19
LPG	2,857	100.1	35.04	2,243	53.8	23.99
Other		1.9	N/A		1.6	N/A
Inventory subtotal	11,573	$ 498.2		3,919	$ 106.0	
Inventory in third-party assets						
Crude oil	1,294	$ 48.7	37.64	853	$ 22.6	26.49
LPG	318	10.6	33.33	183	4.1	22.40
Inventory in third-party assets subtotal	1,612	$ 59.3		1,036	$ 26.7	
Linefill						
Crude oil linefill	6,015	$ 168.4	28.00	3,767	$ 95.9	25.46
Total	19,200	$ 725.9		8,722	$ 228.6	

Property and Equipment

Property and equipment, net is stated at cost and consisted of the following:

	December 31,	
	2004	2003
	(in millions)	
Crude oil pipelines and facilities	$ 1,605.3	$ 1,114.5
Crude oil and LPG storage and terminal facilities	169.6	100.8
Trucking equipment and other	117.6	43.8
Office property and equipment	19.0	13.5
	1,911.5	1,272.6
Less accumulated depreciation	(183.9)	(121.6)
	$ 1,727.6	$ 1,151.0

Depreciation expense for each of the three years in the period ended December 31, 2004, was $63.3 million, $42.4 million and $30.2 million, respectively. Our policy is to depreciate property and equipment over estimated useful lives as follows:

crude oil pipelines and facilities 30 to 40 years;

crude oil and LPG storage and terminal facilities 30 to 40 years;

trucking equipment and other 5 to 15 years; and

office property and equipment 3 to 5 years

We calculate our depreciation and amortization using the straight-line method, based on estimated useful lives and salvage values of our assets. These estimates are based on various factors including age (in the case of acquired assets), manufacturing specifications, technological advances and historical data concerning useful lives of similar assets. Uncertainties that impact these estimates include changes in laws and regulations relating to restoration and abandonment requirements, economic conditions, and supply and demand in the area. When assets are put into service, we make estimates with respect to useful lives and salvage values that we believe are reasonable. However, subsequent events could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization. Historically, adjustments to useful lives have not had a material impact on our aggregate depreciation levels from year to year.

In accordance with our capitalization policy, costs associated with acquisitions and improvements, including related interest costs, which expand our existing capacity are capitalized. For the years ended December 31, 2004, 2003 and 2002, capitalized interest was $0.5 million, $0.5 million and $0.8 million, respectively. In addition, costs required either to maintain the existing operating capacity of partially or fully depreciated assets or to extend their useful lives are capitalized and classified as maintenance capital. Repair and maintenance expenditures associated with existing assets that do not extend the useful life or expand the operating capacity are charged to expense as incurred.

Asset Retirement Obligation

In June 2001, the FASB issued SFAS No. 143 "Asset Retirement Obligations." SFAS 143 establishes accounting requirements for retirement obligations associated with tangible long-lived assets, including (1) the time of the liability recognition, (2) initial measurement of the liability, (3) allocation of asset retirement cost to expense, (4) subsequent measurement of the liability and (5) financial statement disclosures. SFAS 143 requires that the cost for asset retirement should be capitalized as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. Effective January 1, 2003, we adopted SFAS 143, as required. The adoption of this statement did not have a material impact on our financial position, results of operations or cash flows.

Some of our assets, primarily related to our pipeline operations segment, have obligations to perform remediation and, in some instances, removal activities when the asset is abandoned. However, the majority of these obligations are associated with active assets and the fair value of the asset retirement obligations cannot be reasonably estimated, as the settlement dates are indeterminate. A small portion of these obligations relate to assets that are inactive and although the ultimate timing and cost to settle these obligations is not known with certainty, we can reasonably estimate the obligation. As such, we have estimated that the fair value of these obligations is approximately $2.5 million at December 31, 2004. For those obligations that are currently indeterminate, we will record asset retirement obligations in the period in which we can reasonably determine the settlement dates.

Impairment of Long-Lived Assets

Long-lived assets with recorded values that are not expected to be recovered through future cash flows are written-down to estimated fair value in accordance with SFAS No. 144 "Accounting for the Impairment or Disposal of Long-Lived Assets," as amended. Under SFAS 144, an asset shall be tested for impairment when events or circumstances indicate that its carrying value may not be recoverable. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the carrying value exceeds the sum of the undiscounted cash flows, an impairment loss equal to the amount the carrying value exceeds the fair value of the asset is recognized. Fair value is generally determined from estimated discounted future net cash flows. We adopted SFAS 144 on January 1, 2002. In 2004, we recognized a charge of approximately $2.0 million associated with taking our pipeline in the Illinois Basin out of service. The impairment represents the remaining net book value of the idled pipeline system. This pipeline did not support spending the capital necessary to continue service and we shifted the majority of the gathering and transport activities to trucks.

Other Assets

Other assets consist of the following:

	December 31,	
	2004	2003
	(in millions)	
Goodwill	$ 47.1	$ 39.4
Deposit on pending acquisition	11.9	15.8
Debt issue costs	15.5	12.1
Investment in affiliate	8.2	7.8
Fair value of derivative instruments	8.6	5.9
Intangible assets	2.7	2.6
Other	14.0	7.1
	108.0	90.7
Less accumulated amortization	(4.1)	(1.7)
	$ 103.9	$ 89.0

In accordance with SFAS No. 142, "Goodwill and Other Intangible Assets," we test goodwill and other intangible assets periodically to determine whether an impairment has occurred. Goodwill is tested for impairment at a level of reporting referred to as a reporting unit. If the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is considered not impaired. An impairment loss is recognized for intangibles if the carrying amount of an intangible asset is not recoverable and its carrying amount exceeds its fair value. As of December 31, 2004, substantially all of our goodwill is allocated to our gathering, marketing, terminalling and storage operations ("GMT&S"). Since adoption of SFAS 142, the company has not recognized any impairment of goodwill.

Costs incurred in connection with the issuance of long-term debt and amendments to our credit facilities are capitalized and amortized using the straight line method over the term of the related debt. Use of the straight-line method does not differ materially from the "effective interest" method of amortization. Debt issue costs and the related accumulated amortization are written off in conjunction with the refinancing or termination of the applicable debt arrangement. We capitalized costs of approximately $5.9 million and $5.1 million in 2004 and 2003, respectively. In addition, during 2004 we wrote off approximately $0.7 million of unamortized costs and approximately $1.7 million of fully amortized costs and the related accumulated amortization. During 2003, we wrote off comparable amounts totaling $3.3 million and $11.3 million, respectively.

Amortization of other assets for each of the three years in the period ended December 31, 2004, was $3.9 million, $4.4 million and $3.9 million, respectively.

Environmental Matters

We record environmental liabilities when environmental assessments and/or remedial efforts are probable and we can reasonably estimate the costs. Generally, our recording of these accruals coincides with our completion of a feasibility study or our commitment to a formal plan of action. We also record receivables for amounts recoverable from insurance or from third parties under indemnification agreements in the period that we determine the costs are probable of recovery.

We expense or capitalize, as appropriate, environmental expenditures. We expense expenditures that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation. We capitalize environmental liabilities assumed in business combinations based on the fair value of the environmental obligations caused by past operations of the acquired company.

Income and Other Taxes

Except as noted below, no provision for U.S. federal or Canadian income taxes related to our operations is included in the accompanying consolidated financial statements, because as a partnership we are not subject to federal, state or provincial income tax and the tax effect of our activities accrues to the unitholders. Net earnings for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under the partnership agreement. Individual unitholders will have different investment bases depending upon the timing and price of acquisition of partnership units. Further, each unitholder's tax accounting, which is partially dependent upon the unitholder's tax position, may differ from the accounting followed in the consolidated financial statements. Accordingly, there could be significant differences between each individual unitholder's tax bases and the unitholder's share of the net assets reported in the consolidated financial statements. We do not have access to information about each individual unitholder's tax attributes, and the aggregate tax basis cannot be readily determined. Accordingly, we do not believe that in our circumstances, the aggregate difference would be meaningful information.

The Partnership's Canadian operations are conducted through an operating limited partnership, of which our wholly owned subsidiary PMC (Nova Scotia) Company is the general partner. For Canadian tax purposes, the general partner is taxed as a corporation, subject to income taxes and a capital-based tax at federal and provincial levels. For the years presented, these amounts were immaterial.

In addition to federal income taxes, owners of our common units may be subject to other taxes, such as state and local and Canadian federal and provincial taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that may be imposed by the various jurisdictions in which we do business or own property. A unitholder may be required to file Canadian federal income tax returns, pay Canadian federal and provincial income taxes, file state income tax returns and pay taxes in various states.

Recent Accounting Pronouncements

In March 2004, the Emerging Issues Task Force issued Issue No. 03-06 ("EITF 03-06"), "Participating Securities and the Two-Class Method under FASB Statement No. 128." EITF 03-06 addresses a number of questions regarding the computation of earnings per share by companies that have issued securities, other than common stock, that contractually entitle the holder to participate in dividends and earnings of the company when, and if, it declares dividends on its common stock. The issue also provides further guidance in applying the two-class method of calculating earnings per share, clarifying what constitutes a participating security and how to apply the two-class method of computing earnings per share once it is determined that a security is participating, including how to allocate undistributed earnings to such a security. EITF 03-06 was effective for fiscal periods beginning after March 31, 2004. There was no impact on earnings per limited partner unit in the periods presented because of the adoption of EITF 03-06. The adoption of EITF 03-06 may have an impact on earnings per limited partner unit in future periods if net income exceeds distributions or if other participating securities are issued.

Derivative Instruments and Hedging Activities

We utilize various derivative instruments to (i) manage our exposure to commodity price risk, (ii) engage in a controlled trading program, (iii) manage our exposure to interest rate risk and (iv) manage our exposure to currency exchange rate risk. We record all derivative instruments on the balance sheet as either assets or liabilities measured at their fair value under the provisions of SFAS 133, "Accounting for Derivative Instruments and Hedging Activities" as amended by SFAS 137 and SFAS 138 (collectively "SFAS 133"). SFAS 133 requires that changes in derivative instruments fair value be recognized currently in earnings unless specific hedge accounting criteria are met, in which case, changes in fair value are deferred to Other Comprehensive Income ("OCI") and reclassified into earnings when the underlying transaction affects earnings. Accordingly, changes in fair value are included in the current period for (i) derivatives characterized as fair value hedges, (ii) derivatives that do not qualify for hedge accounting and (iii) the portion of cash flow hedges that is not highly effective in offsetting changes in cash flows of hedged items.

Net Income Per Unit

Basic and diluted net income per unit is determined by dividing net income after deducting the amount allocated to the general partner interest, (including its incentive distribution in excess of its 2% interest), by the weighted average number of outstanding limited partner units during the period, including common units and subordinated units. Partnership income is first allocated to the general partner based on the amount of incentive distributions. The remainder is then allocated between the limited partners and general partner based on percentage ownership in the Partnership. The following table sets forth the computation of basic and diluted net income per limited partner unit for 2004, 2003 and 2002.

	Year ended December 31,		
	2004	2003	2002
Net income	$ 130,006	$ 59,448	$ 65,292
Less:			
Incentive distribution right	(8,286)	(4,884)	(3,137)
Subtotal	121,720	54,564	62,155
General partner 2% ownership	(2,434)	(1,091)	(1,243)
Numerator for basic earnings per limited partner unit:			
Net income available for limited partners	119,286	53,473	60,912
Effect of dilutive securities:			
Increase in general partner's incentive distribution-contingent equity issuance		(61)	
Numerator for diluted earnings per limited partner unit	$ 119,286	$ 53,412	$ 60,912
Denominator:			
Denominator for basic earnings per limited partner unit weighted average number of limited partner units	63,277	52,743	45,546
Effect of dilutive securities:			
Contingent equity issuance		657	
Denominator for diluted earnings per limited partner unit weighted average number of limited partner units	63,277	53,400	45,546
Basic net income per limited partner unit	$ 1.89	$ 1.01	$ 1.34
Diluted net income per limited partner unit	$ 1.89	$ 1.00	$ 1.34

Note 3 Acquisitions

The following acquisitions were accounted for using the purchase method of accounting and the purchase price was allocated in accordance with such method. In addition, we adopted SFAS No. 141, "Business Combinations" in 2001 and followed the provisions of that statement for all business combinations initiated after June 30, 2001.

Significant Acquisitions

Link Energy LLC

On April 1, 2004, we completed the acquisition of all of the North American crude oil and pipeline operations of Link Energy LLC ("Link") for approximately $332 million, including $268 million of cash (net of approximately $5.5 million subsequently returned to us from an indemnity escrow account) and approximately $64 million of net liabilities assumed and acquisition-related costs. The Link crude oil business consists of approximately 7,000 miles of active crude oil pipeline and gathering systems, over 10 million barrels of active crude oil storage capacity, a fleet of approximately 200 owned or leased trucks and approximately 2 million barrels of crude oil linefill and working inventory. The Link assets complement our assets in West Texas and along the Gulf Coast and allow us to expand our presence in the Rocky Mountain and Oklahoma/Kansas regions. The results of operations and assets and liabilities from this acquisition (the "Link acquisition") have been included in our consolidated financial statements and in both our pipeline operations and gathering, marketing, terminalling and storage operations segments since April 1, 2004.

The purchase price was allocated as follows and includes goodwill primarily related to Link's gathering and marketing business (in millions):

Cash paid for acquisition[1]	$	268.0
Fair value of net liabilities assumed:		
Accounts receivable[2]		409.4
Other current assets		1.8
Accounts payable and accrued liabilities[2]		(459.6)
Other current liabilities		(8.5)
Other long-term liabilities		(7.4)
Total net liabilities assumed		(64.3)
Total purchase price	$	332.3
Purchase price allocation		
Property and equipment	$	260.2
Inventory		3.4
Linefill		55.4
Inventory in third party assets		8.1
Goodwill		5.0
Other long term assets		0.2
Total	$	332.3

(1) Cash paid does not include the subsequent payment of various transaction and other acquisition related costs.

(2) Accounts receivable and accounts payable are gross and do not reflect the adjustment of approximately $250 million to net settle, based on contractual agreements with our counterparties.

The total purchase price includes (i) approximately $9.4 million in transaction costs, (ii) approximately $7.4 million related to a plan to involuntarily terminate and relocate employees in conjunction with the acquisition, and (iii) approximately $11.0 million related to costs to terminate a contract assumed in the acquisition. These activities are substantially complete and the majority of the related costs have been incurred as of December 31, 2004. In addition, we anticipate making capital expenditures of approximately $28.0 million ($18.0 million in 2005) to upgrade certain of the assets and comply with certain regulatory requirements.

The acquisition was initially funded with cash on hand, borrowings under our existing revolving credit facilities and under a new $200 million, 364-day credit facility. In connection with the acquisition, on April 15, 2004, we completed the private placement of 3,245,700 Class C common units to a group of institutional investors. During the third quarter of 2004, we completed a public offering of common units and the sale of an aggregate of $350 million of senior notes. A portion of the proceeds from these transactions was used to retire the $200 million, 364-day credit facility.

In connection with the Link purchase, both PAA and Link completed all necessary filings required under the Hart-Scott-Rodino Act, and the required 30-day waiting period expired on March 24, 2004 without any inquiry or request for additional information from the U.S. Department of Justice or the Federal Trade Commission (the "FTC"). On April 2, 2004, the Office of the Attorney General of Texas (the "Texas AG") delivered written notice to us that it was investigating the possibility that the acquisition of Link's assets might reduce competition in one or more markets within the petroleum products industry in the State of Texas. Such investigation was coordinated with the FTC, consistent with federal-state protocols for conducting joint merger investigations. We cooperated fully with the antitrust enforcement authorities, including the provision of information at the request of the Texas AG Antitrust Division. In late 2004, we were informed by the Texas AG Antitrust Division and subsequently by the FTC that they were closing their investigation and do not have any current intentions to pursue any additional course of action with respect to these assets.

Capline and Capwood Pipeline Systems

In March 2004, we completed the acquisition of all of Shell Pipeline Company LP's interests in two entities for approximately $158.0 million in cash (including a $15.8 million deposit paid in December 2003) and approximately $0.5 million of transaction and other costs. In December 2003, subsequent to the announcement of the acquisition and in anticipation of closing, we issued approximately 2.8 million common units for net proceeds of approximately $88.4 million, after paying approximately $4.1 million of transaction costs. The proceeds from this issuance were used to pay down our revolving credit facility. At closing, the cash portion of this acquisition was funded from cash on hand and borrowings under our revolving credit facility.

The principal assets of these entities are: (i) an approximate 22% undivided joint interest in the Capline Pipeline System, and (ii) an approximate 76% undivided joint interest in the Capwood Pipeline System. The Capline Pipeline System is a 633-mile, 40-inch mainline crude oil pipeline originating in St. James, Louisiana, and terminating in Patoka, Illinois. The Capwood Pipeline System is a 57-mile, 20-inch mainline crude oil pipeline originating in Patoka, Illinois, and terminating in Wood River, Illinois. The results of operations and assets from this acquisition (the "Capline acquisition") have been included in our consolidated financial statements and in our pipeline operations segment since

March 1, 2004. These pipelines provide one of the primary transportation routes for crude oil shipped into the Midwestern U.S., and delivered to several refineries and other pipelines.

The purchase price was allocated as follows (in millions):

Crude oil pipelines and facilities	$ 151.4
Crude oil storage and terminal facilities	5.7
Land	1.3
Office equipment and other	0.1
Total	$ 158.5

Pro Forma Data

The following unaudited pro forma data is presented to show pro forma revenues, income before cumulative effect of change in accounting principle, net income, basic and diluted income before cumulative effect of accounting change per limited partner unit and basic and diluted net income per limited partner unit for the Partnership as if the Capline and Link acquisitions had occurred as of the beginning of the periods reported:

	Year Ended December 31,	
	2004	**2003**
	(unaudited) (in millions, except per unit amounts)	
Revenues	$ 21,023.4	$ 12,807.5
Income before cumulative effect of change in accounting principle[(1)]	$ 115.9	$ 110.4
Net income[(2)]	$ 112.8	$ 106.4
Basic income before cumulative effect of change in accounting principle per limited partner unit[(1)]	$ 1.77	$ 1.97
Diluted income before cumulative effect of change in accounting principle per limited partner unit[(1)]	$ 1.77	$ 1.94
Basic net income per limited partner unit[(2)]	$ 1.72	$ 1.90
Diluted net income per limited partner unit[(2)]	$ 1.72	$ 1.87

(1) Includes a net gain in the 2003 period of approximately $67.5 million related to Link's predecessor company's reorganization, discharge of debt and fresh start adjustments.

(2) The 2003 period includes the amounts described in note (1) above as well as a loss of approximately $4.0 million related to Link's predecessor company's cumulative effect of change in accounting principle.

Shell West Texas Assets

On August 1, 2002, we acquired from Shell Pipeline Company LP and Equilon Enterprises LLC interests in approximately 2,000 miles of gathering and mainline crude oil pipelines and approximately 9.0 million barrels (net to our interest) of above-ground crude oil terminalling and storage assets in West Texas (the "Shell acquisition"). The results of operations and assets from this acquisition have been included in our consolidated financial statements and in our pipeline operations segment since that date. The primary assets included in the transaction were interests in the Basin Pipeline System, the Permian Basin Gathering System and the Rancho Pipeline System. These assets complement our existing asset infrastructure in West Texas and represent a transportation link to Cushing, Oklahoma, where we are a provider of storage and terminalling services. The total purchase price of $324.4 million consisted of (i) $304.0 million in cash, which was borrowed under our revolving credit facility, (ii) approximately $9.1 million related to the settlement of pre-existing accounts receivable and inventory balances and (iii) approximately $11.3 million of estimated transaction and closing costs. The entire purchase price was allocated to property and equipment.

Other Acquisitions

2004 Acquisitions

During 2004, in addition to the Link and Capline acquisitions, we completed several other acquisitions for aggregate consideration totaling $58.7 million including transaction costs. These acquisitions include crude oil mainline and gathering pipelines and propane storage facilities. The aggregate purchase price was allocated to property and equipment.

2003 Acquisitions

During 2003, we completed ten acquisitions for aggregate consideration totaling approximately $159.5 million. The aggregate consideration includes cash paid, estimated transaction costs, assumed liabilities and estimated near-term capital costs. These acquisitions included mainline crude oil pipelines, crude oil gathering lines, terminal and storage facilities, and an underground LPG storage facility. The aggregate purchase price was allocated as follows (in million):

Crude oil pipelines and facilities	$	138.0
Crude oil and LPG storage facilities		7.3
Trucking equipment and other		7.8
Office property and equipment		1.2
Pipeline Linefill		4.7
Goodwill		0.5
	$	159.5

2002 Acquisitions

During 2002, in addition to the Shell acquisition, we completed two acquisitions for aggregate consideration totaling approximately $15.9 million including transaction costs. These acquisitions include crude oil pipeline, gathering and marketing assets and a 22% equity interest in a pipeline company. With the exception of $1.3 million that was allocated to goodwill, the aggregate purchase price was allocated to property and equipment.

Note 4 Asset Dispositions

Shutdown and Sale of Rancho Pipeline System

We acquired an interest in the Rancho Pipeline System from Shell in August 2002. The Rancho Pipeline System Agreement dated November 1, 1951, pursuant to which the system was constructed and operated, terminated in March 2003. Upon termination, the agreement required the owners to take the pipeline system, in which we owned an approximate 50% interest, out of service. Accordingly, we notified our shippers and did not accept nominations for movements after February 28, 2003. This shutdown was contemplated at the time of the acquisition and was accounted for under purchase accounting in accordance with SFAS No. 141 "Business Combinations." The pipeline was shut down on March 1, 2003 and a purge of the crude oil linefill was completed in April 2003. In June 2003, we completed transactions whereby we transferred our ownership interest in approximately 241 miles of the total 458 miles of the pipeline in exchange for $4.0 million and approximately 500,000 barrels of crude oil tankage in West Texas. In August 2004, we sold our interest in the remaining portion of the system for approximately $0.9 million, including the assumption of all liabilities typically associated with pipelines of this type. We recognized a gain of approximately $0.6 million on this transaction.

Other Dispositions

During 2004, 2003 and 2002, we sold various other property and equipment for proceeds totaling approximately $3.0 million, $8.5 million and $1.4 million, respectively. Gains of approximately $0.6 million were recognized in both 2004 (including the gain on the sale of the Rancho Pipeline System) and 2003, respectively, and no gain or loss was recognized in 2002.

Note 5 Debt

Debt consists of the following:

	December 31, 2004	December 31, 2003
	(in millions)	
Short-term debt:		
Senior secured hedged inventory borrowing facility bearing interest at a rate of 3.0% and 1.9% at December 31, 2004 and December 31, 2003, respectively	$ 80.4	$ 100.5
Working capital borrowings, bearing interest at a rate of 3.7% and 4.0% at December 31, 2004 and December 31, 2003, respectively[1]	88.2	25.3
Other	6.9	1.5
Total short-term debt	175.5	127.3
Long-term debt:		
Senior unsecured revolving credit facility, bearing interest at 3.5% at December 31, 2004[1]	$ 143.6	$
Senior unsecured $170 million Canadian revolving credit facility, bearing interest at a rate of 2.2% at December 31, 2003		70.0
4.75% senior notes due August 2009, net of unamortized discount of $0.7 million at December 31, 2004	174.3	
7.75% senior notes due October 2012, net of unamortized discount of $0.3 million and $0.3 million at December 31, 2004 and December 31, 2003, respectively	199.7	199.7
5.63% senior notes due December 2013, net of unamortized discount of $0.6 million and $0.7 million at December 31, 2004 and December 31, 2003, respectively	249.4	249.3
5.88% senior notes due August 2016, net of unamortized discount of $1.1 million at December 31, 2004	173.9	
Other	8.1	
Total long-term debt[1]	949.0	519.0
Total debt	$ 1,124.5	$ 646.3

(1) At December 31, 2004 and 2003, we have classified $88.2 million and $25.3 million, respectively, of borrowings under our senior unsecured revolving credit facility as short-term. These borrowings are designated as working capital borrowings under this facility and primarily are for hedged LPG inventory and New York Mercantile Exchange ("NYMEX") margin deposits and must be repaid within one year.

Credit Facilities

In November 2004, we entered into a new $750 million, five-year senior unsecured credit facility, which contains a sub-facility for Canadian borrowings of up to $300 million. The new credit facility extends our maturities, lowers our cost of credit and provides an additional $125 million of liquidity over our previous facilities. This facility can be expanded to $1 billion. At December 31, 2004, approximately $231.8 million was outstanding under this facility (including $88.2 million classified as short-term).

Also in the fourth quarter of 2004, we amended and renewed our senior secured hedged inventory facility; increasing the facility to $425 million, with the ability to further increase the facility in the future by an incremental $75 million. This facility is an uncommitted working capital facility, which is used to finance the purchase of hedged crude oil inventory for storage when market conditions warrant. Borrowings under the hedged inventory facility are collateralized by the inventory purchased under the facility and the associated accounts receivable, and will be repaid with the proceeds from the sale of such inventory. This facility expires in November 2005.

Senior Notes

During August 2004, we completed the sale of $175 million of 4.75% Senior Notes due 2009 and $175 million of 5.88% Senior Notes due 2016. The 4.75% notes were sold at 99.551% of face value and the 5.88% notes were sold at 99.345% of face value. Interest payments are due on February 15 and August 15 of each year.

During December 2003, we completed the sale of $250 million of 5.625% senior notes due in December 2013. The notes were issued at a discount of $0.7 million, resulting in an effective interest rate of 5.66%. Interest payments are due on June 15 and December 15 of each year.

During September 2002, we completed the sale of $200 million of 7.75% senior notes due in October 2012. The notes were issued at a discount of $0.4 million, resulting in an effective interest rate of 7.78%. Interest payments are due on April 15 and October 15 of each year.

In each instance, the notes were co-issued by Plains All American Pipeline, L.P. and a 100% owned consolidated finance subsidiary (neither of which have independent assets or operations) and are fully and unconditionally guaranteed, jointly and severally, by all of our existing 100% owned subsidiaries, except for subsidiaries which are minor.

Covenants and Compliance

Our credit agreements and the indentures governing the senior notes contain cross default provisions. Our credit agreements prohibit distributions on, or purchases or redemptions of, units if any default or event of default is continuing. In addition, the agreements contain various covenants limiting our ability to, among other things:

- incur indebtedness if certain financial ratios are not maintained;
- grant liens;
- engage in transactions with affiliates;
- enter into sale-leaseback transactions;
- sell substantially all of our assets or enter into a merger or consolidation.

Our credit facility treats a change of control as an event of default and also requires us to maintain:

- an interest coverage ratio that is not less than 2.75 to 1.0; and
- a debt coverage ratio which will not be greater than 4.75 to 1.0 on all outstanding debt and 5.25 to 1.0 on all outstanding debt during an acquisition period (generally, the period consisting of three fiscal quarters following an acquisition greater than $50 million).

For covenant compliance purposes, letters of credit and borrowings to fund hedged inventory and margin requirements are excluded when calculating the debt coverage ratio.

A default under our credit facility would permit the lenders to accelerate the maturity of the outstanding debt. As long as we are in compliance with our credit agreements, our ability to make distributions of available cash is not restricted. We are currently in compliance with the covenants contained in our credit agreements and indentures.

Letters of Credit

As is customary in our industry, and in connection with our crude oil marketing, we provide certain suppliers and transporters with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. These letters of credit are issued under our credit facility, and our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the crude oil is purchased. Generally, these letters of credit are issued for up to seventy-day periods and are terminated upon completion of each transaction. At December 31, 2004 and 2003, we had outstanding letters of credit of approximately $98.0 million and $57.9 million, respectively. In addition to changes in the level of activity and other factors, the amount of letters of credit outstanding varies based on NYMEX crude oil prices, which were $43.34 per barrel and $32.52 per barrel at December 31, 2004 and 2003, respectively.

Maturities

The weighted average life of our long-term debt outstanding at December 31, 2004, was approximately 8 years and the aggregate maturities for the for the next five years are as follows:

Calendar Year	Payment
2005	$
2006	3.7
2007	3.6
2008	0.8
2009	318.6
Thereafter	625.0
Total[1]	$ 951.7

(1) Reflects aggregate unamortized discount of $2.7 million on our various senior notes.

Note 6 Partners' Capital and Distributions

Units Outstanding

Partners' capital at December 31, 2004 consists of 67,293,108 common units, including 1,307,190 Class B common units and 3,245,700 Class C common units, representing a 98% effective aggregate ownership interest in the Partnership and its subsidiaries, (after giving affect to the general partner interest), and a 2% general partner interest.

Class B and Class C Common Units

The Class B common units and Class C common units were *pari passu* with common units with respect to quarterly distributions. In accordance with a common unitholder vote at a special meeting on January 20, 2005, each Class B common unit and Class C common unit became convertible into one common unit upon request of the holder. In February 2005, all of the Class B and Class C common units converted into common units.

Subordinated Units and Conversion

Pursuant to the terms of our Partnership Agreement and having satisfied the financial tests contained therein, in November 2003, 25% of the subordinated units converted to common units on a one-for-one basis. In February 2004, all of the remaining subordinated units converted to common units on a one-for-one basis.

The subordinated units have a debit balance in Partners' Capital of approximately $39.9 million at December 31, 2003. The debit balance is the result of several different factors including: (i) a low initial capital balance in connection with the formation of the Partnership as a result of a low carry-over book basis in the assets contributed to the Partnership at the date of formation, (ii) a significant net loss in 1999 and (iii) distributions to unitholders that have exceeded net income allocated to unitholders each period. Additionally, the capital balances of the common unitholders and the General Partner have increased periodically as additional units have been sold and as the General Partner has made additional capital contributions associated with those offerings. The subordinated unitholders are not required to make any additional contributions associated with those offerings of common units. No additional subordinated units were issued after the initial issuance.

General Partner Incentive Distributions

Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, generally the general partner is entitled, without duplication, to 15% of amounts we distribute in excess of $0.450 per unit, referred to as our minimum quarterly distributions ("MQD"), 25% of the amounts we distribute in excess of $0.495 per unit and 50% of amounts we distribute in excess of $0.675 per unit (referred to as "incentive distributions"). Cash distributions on our outstanding units and the portion of the distributions representing an excess over the MQD were as follows:

	Year					
	2004		2003		2002	
	Distribution[(1)]	Excess over MQD	Distribution[(1)]	Excess over MQD	Distribution[(1)]	Excess over MQD
First Quarter	$ 0.5625	$ 0.1125	$ 0.5375	$ 0.0875	$ 0.5125	$ 0.0625
Second Quarter	$ 0.5625	$ 0.1125	$ 0.5500	$ 0.1000	$ 0.5250	$ 0.0750
Third Quarter	$ 0.5775	$ 0.1275	$ 0.5500	$ 0.1000	$ 0.5375	$ 0.0875
Fourth Quarter	$ 0.6000	$ 0.1500	$ 0.5500	$ 0.1000	$ 0.5375	$ 0.0875

(1) Distributions represent those declared and paid in the applicable period.

Distributions

We will distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established by our general partner for future requirements. Total cash distributions made were as follows:

					GP							
Year		**Common Units**		**Subordinated Units**		**2%**		**Incentive**		**Total**		**Distribution per unit**
	(in millions, except per unit amounts)											
2004	$	142.9	$	4.2	$	3.0	$	8.3	$	158.4	$	2.30
2003	$	92.7	$	21.9	$	2.3	$	4.9	$	121.8	$	2.19
2002	$	73.6	$	21.1	$	2.0	$	3.1	$	99.8	$	2.11

On January 25, 2005, we declared a cash distribution of $0.6125 per unit on our outstanding common units, Class B common units and Class C common units. The distribution was paid on February 14, 2005, to unitholders of record on February 4, 2005, for the period October 1, 2004, through December 31, 2004. The total distribution paid was approximately $45.0 million, with approximately $41.2 million paid to our common unitholders and $0.8 million and $3.0 million paid to our general partner for its general partner and incentive distribution interests, respectively.

Equity Offerings

During the three years ended December 31, 2004, we completed the following public equity offerings of our common units:

Period	**Units**		**Gross Unit Price**		**Proceeds from Sale**		**GP Contribution**		**Costs**		**Net Proceeds**
	(in millions, except per unit amounts)										
July/August 2004	4,968,000	$	33.25	$	165.2	$	3.4	$	7.7	$	160.9
December 2003	2,840,800	$	31.94	$	90.7	$	1.8	$	4.1	$	88.4
September 2003	3,250,000	$	30.91	$	100.5	$	2.1	$	4.6	$	98.0
March 2003	2,645,000	$	24.80	$	65.6	$	1.3	$	3.0	$	63.9
August 2002	6,325,000	$	23.50	$	148.6	$	3.0	$	6.6	$	145.0

Private Placement of Class C Common Units

In connection with the Link acquisition, on April 15, 2004 we issued 3,245,700 Class C common units for $30.81 per unit in a private placement to a group of institutional investors consisting of affiliates of Kayne Anderson Capital Advisors, Vulcan Capital and Tortoise Capital Advisors. Affiliates of both Kayne Anderson Capital Advisors and Vulcan Capital own interests in our general partner. Total proceeds from the transaction, after deducting transaction costs and including the general partner's proportionate contribution, were approximately $101 million, and were used to reduce the balance outstanding under our revolving credit facilities. The Class C common units were unlisted securities that are *pari passu* in voting and distribution rights with the Partnership's publicly traded common units. The Class C common units were similar in most respects to the Partnership's Class B common units. Both classes became convertible on a one-for-one basis into common units upon approval by the holders of a majority of the common units at a special meeting of our unitholders held on January 20, 2005. All of the Class B common units and Class C common units converted in February 2005.

Payment of Deferred Acquisition Price

In connection with the CANPET acquisition in July 2001, $26.5 million Canadian of the purchase price, payable in common units or cash at our option, was deferred subject to various performance objectives being met. These objectives were met as of December 31, 2003 and an increase to goodwill for this liability was recorded as of that date. The liability was satisfied on April 30, 2004 with the issuance of approximately 385,000 common units and the payment of $6.5 million in cash. The number of common units issued in satisfaction of the deferred payment was based upon $34.02 per share, the average trading price of our common units for the ten-day trading period prior to the payment date, and a Canadian dollar to U.S. dollar exchange rate of 1.35 to 1, the average noon-day exchange rate for the ten-day trading period prior to the payment date. In addition, an incremental $3.7 million in cash was paid for the distributions that would have been paid on the common units had they been outstanding since the effective date of the acquisition.

Note 7 Derivatives and Financial Instruments

We utilize various derivative instruments to (i) manage our exposure to commodity price risk, (ii) engage in a controlled trading program, (iii) manage our exposure to interest rate risk and (iv) manage our exposure to currency exchange rate risk. Our risk management policies and procedures are designed to monitor interest rates, currency exchange rates, NYMEX and over-the-counter positions, and physical volumes, grades, locations and delivery schedules to ensure that our hedging activities address our market risks. We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategy for undertaking the hedge. We calculate hedge effectiveness on a quarterly basis. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument's effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items.

Summary of Financial Impact

The following is a summary of the financial impact of the derivative instruments and hedging activities discussed below. The December 31, 2004, balance sheet includes assets of $63.9 million ($55.2 million current), liabilities of $29.5 million ($18.9 million current) and unrealized net gains deferred to Other Comprehensive Income ("OCI") of $25.9 million. Total derivative activities for the year ended December 31, 2004, generated a gain of $35.1 million. This gain includes (i) derivatives that do not qualify for hedge accounting (a gain of approximately $0.9 million), (ii) the portion of cash flow hedges that is not highly effective in offsetting changes in cash flows of hedged items (a gain of approximately $0.1 million), and (iii) gains and losses recognized in earnings for all hedges settled during the period (a net gain of approximately $34.1 million). The majority of these gains are related to our commodity price risk hedging activities that are offset by physical transactions, as discussed below.

As of December 31, 2004, the total amount of deferred net gains recorded in OCI are expected to be reclassified to future earnings, contemporaneously with the related physical purchase or delivery of the underlying commodity or payments of interest. During the year ended December 31, 2004, no amounts were reclassified to earnings from OCI in connection with forecasted transactions that were no longer considered probable of occurring. Of the $25.9 million net gain deferred in OCI at December 31, 2004, a net gain of $34.7 million will be reclassified into earnings in the next twelve months and the remaining net loss at various intervals (ending in 2016 for amounts related to our terminated interest rate swaps and 2009 for amounts related to our commodity price risk hedging). Since a portion of these amounts is based on market prices at the current period end, actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

The following sections discuss our risk management activities in the indicated categories.

Commodity Price Risk Hedging

We hedge our exposure to price fluctuations with respect to crude oil and LPG in storage, and expected purchases, sales and transportation of these commodities. The derivative instruments we use consist primarily of futures and option contracts traded on the NYMEX and over-the-counter transactions, including crude oil swap and option contracts entered into with financial institutions and other energy companies. In accordance with SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities," as amended, these derivative instruments are recognized in the balance sheet or earnings at their fair values. The majority of the instruments that qualify for hedge accounting are cash flow hedges. Therefore, the corresponding changes in fair value for the effective portion of the hedges are deferred into OCI and recognized in revenues or crude oil and LPG purchases and related costs in the periods during which the underlying physical transactions occur. We have determined that substantially all of our physical purchase and sale agreements qualify for the normal purchase and sale exclusion and thus are not subject to SFAS 133. Physical transactions that are derivatives and are ineligible, or become ineligible, for the normal purchase and sale treatment (e.g. due to changes in settlement provisions) are recorded in the balance sheet as assets or liabilities at their fair value, with the changes in fair value recorded net in revenues.

Controlled Trading Program

Although we seek to maintain a position that is substantially balanced within our crude oil lease purchase activities, we may experience net unbalanced positions for short periods of time as a result of production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions. In connection with managing these positions and maintaining a constant presence in the marketplace, both necessary for our core business, we engage in a controlled trading program for up to an aggregate of 500,000 barrels of crude oil. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. In accordance with SFAS 133, these derivative instruments are recorded in the balance sheet as assets or liabilities at their fair value, with the changes in fair value recorded net in revenues.

Interest Rate Risk Hedging

At December 31, 2004, we have no open interest rate hedging instruments. However, there are approximately $6.1 million deferred in OCI that relates to cash flow hedge instruments that were terminated and cash settled ($1.4 million related to an instrument settled in 2004 and $4.7 million related to instruments settled in 2003) that relate to debt agreements refinanced in 2004 and 2003, respectively. The deferred loss related to these instruments is being amortized into interest expense over the original terms of the terminated instruments (approximately $2.9 million over the next two years and the remaining $3.2 million over approximately ten years). Approximately $1.5 million related to the terminated instruments were reclassified into interest expense during 2004. In addition, earnings for 2004 include a loss of approximately $0.7 million that was reclassified out of OCI related to an instrument that matured in March 2004.

Currency Exchange Rate Risk Hedging

Because a significant portion of our Canadian business is conducted in Canadian dollars and, at times, a portion of our debt is denominated in Canadian dollars, we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments include forward exchange contracts and cross currency swaps. Neither the forward exchange contracts nor the cross currency swaps qualify for hedge accounting in accordance with SFAS 133.

At December 31, 2004, we had forward exchange contracts that allow us to exchange Canadian dollars for U.S. dollars, quarterly, at set exchange rates as detailed below:

	Canadian Dollars	US Dollars	Rate
	($ in millions)		
2005	$3.0	$2.3	1.33 to 1
2006	$2.0	$1.5	1.32 to 1

In addition, at December 31, 2004, we also had cross currency swap contracts for an aggregate notional principal amount of $21.0 million, effectively converting this amount of our U.S. dollar denominated debt to $32.5 million of Canadian dollar debt (based on a Canadian dollar to U.S. dollar exchange rate of 1.55 to 1). The notional principal amount will reduce by $2.0 million U.S. in May 2005 and has a final maturity in May 2006 of $19.0 million U.S. At December 31, 2004, $9.9 million of our long-term debt was denominated in Canadian dollars ($11.9 million Canadian based on a Canadian dollar to U.S. dollar exchange rate of 1.20 to 1). All of these financial instruments are placed with what we believe to be large, creditworthy financial institutions.

Fair Value of Financial Instruments

The carrying amounts and fair values of our financial instruments are as follows (in millions):

	December 31,			
	2004		2003	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
NYMEX futures	$42.3	$42.3	$7.5	$7.5
Options and swaps	$(2.8)	$(2.8)	$(3.3)	$(3.3)
Forward exchange contracts	$(1.5)	$(1.5)	$(0.4)	$(0.4)
Cross currency swaps	$(6.3)	$(6.3)	$(4.8)	$(4.8)
Interest rate swaps	$	$	$(0.4)	$(0.4)
Short and long-term debt under credit facilities	$231.8	$231.8	$95.3	$95.3
Borrowings under senior secured hedged inventory facility	$80.4	$80.4	$100.5	$100.5
Senior notes	$797.3	$848.0	$449.0	$482.9

As of December 31, 2004 and 2003, 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 variable rate instruments in our credit facilities and senior secured hedged inventory facility approximate fair value primarily because the interest rates fluctuate with prevailing market rates, and the credit spread on outstanding borrowings reflects market. The interest rate on our senior notes (7.75%, 5.88%, 5.63%, and 4.75%) is fixed and the fair value is based on quoted market prices.

The carrying amount of our derivative financial instruments approximate fair value as these instruments are recorded on the balance sheet at their fair value under SFAS 133. Our derivative financial instruments include cross currency swaps, forward exchange and extra option contracts, interest rate swap, collar and treasury lock agreements for which fair values are based on current liquidation values. We also have over-the-counter option and swap contracts for which fair values are estimated based on various sources such as independent reporting services, industry publications and brokers. For positions where independent quotations are not available, an estimate is provided, or the prevailing market price at which the positions could be liquidated is used. In addition, we have NYMEX futures and options for which the fair values are based on quoted market prices.

Note 8 Major Customers and Concentration of Credit Risk

Marathon Ashland Petroleum ("MAP") accounted for 10%, 12% and 10% of our revenues for each of the three years in the period ended December 31, 2004. BP Oil Supply also accounted for 10% of our revenues for the year ended December 31, 2004. No other customers accounted for 10% or more of our revenues during any of the three years. The majority of the revenues from MAP and BP Oil Supply pertain to our gathering, marketing, terminalling and storage operations. We believe that the loss of these customers would have only a short-term impact on our operating results. There can be no assurance, however, that we would be able to identify and access a replacement market at comparable margins.

Financial instruments that potentially subject us to concentrations of credit risk consist principally of trade receivables. Our accounts receivable are primarily from purchasers and shippers of crude oil. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic, industry or other conditions. We review credit exposure and financial information of our counterparties and generally require letters of credit for receivables from customers that are not considered credit worthy, unless the credit risk can otherwise be reduced.

Note 9 Related Party Transactions

Reimbursement of Expenses of Our General Partner and Its Affiliates

We do not directly employ any persons to manage or operate our business. These functions are provided by employees of our general partner (or, in the case of our Canadian operations, PMC (Nova Scotia) Company). Our general partner does not receive a management fee or other compensation in connection with its management of us. We reimburse our general partner for all direct and indirect costs of services provided, including the costs of employee, officer and director compensation and benefits allocable to us, and all other expenses necessary or appropriate to the conduct of our business, and allocable to us. Our agreement provides that our general partner will determine the expenses allocable to us in any reasonable manner determined by our general partner in its sole discretion. Total costs reimbursed by us to our general partner for the years ended December 31, 2004, 2003 and 2002 were approximately $151.0 million, $88.1 million and $70.8 million, respectively.

Crude Oil Marketing Agreement

As of December 31, 2004, Vulcan Energy, through its wholly-owned subsidiary Plains Resources, owned an effective 44% of our general partner interest, as well as approximately 18.3% of our outstanding limited partner units. We are the exclusive marketer/purchaser for all of Plains Resources' and its subsidiaries' equity crude oil production. We have a marketing agreement with Plains Resources (the "Marketing Agreement") whereby we will purchase for resale at market prices the majority of Plains Resources' crude oil production for which we charge a fee of $0.20 per barrel. This fee is subject to adjustment every three years based on then-existing market conditions. For the years ended December 31, 2004, 2003 and 2002, we paid Plains Resources approximately $28.3 million, $25.7 million and $247.7 million, respectively, for the purchase of crude oil under the agreement, including the royalty share of production, and recognized margins of approximately $0.1 million, $0.2 million and $1.8 million from the marketing fee for the same periods, respectively. In our opinion, these purchases were made at prevailing market prices. In connection with the separation of Plains Resources and one of its subsidiaries, discussed below, Plains Resources divested the bulk of its producing properties. As a result, we do not anticipate the marketing arrangement with Plains Resources to be material to our operating results in the future. As currently in effect, the Marketing Agreement will terminate upon a "change of control" of Plains Resources or our general partner. The recent purchase of Plains Resources by Vulcan Energy would have constituted a change of control under the Marketing Agreement. In July 2004, we amended and restated the Marketing Agreement to exclude the Vulcan transaction from the change of control provisions.

In December 2002, Plains Resources completed a spin-off of one of its subsidiaries, Plains Exploration and Production Company ("PXP") to its shareholders. PXP is a successor participant to the Marketing Agreement. For the years ended December 31, 2004 and 2003, we paid PXP approximately $328.3 million and $277.9 million, respectively, for the purchase of crude oil under the agreement, including the royalty share of production and recognized margins of approximately $1.4 and $1.7 million, respectively, from the marketing fee. In our opinion, these purchases were made at prevailing market prices. We are also party to a Letter Agreement with Stocker Resources, L.P. (now PXP) that provides that if the Marketing Agreement terminates before our crude oil sales agreement with Tosco Refining Co. ("Tosco") terminates, PXP will continue to sell and we will continue to purchase PXP's equity crude oil production from the Arroyo Grande field (now owned by a subsidiary of PXP) under the same terms as the Marketing Agreement until our Tosco sales agreement terminates. In July 2004, we amended and restated the Marketing Agreement to, among other things, reflect the change in parties as a result of the spin-off. We sell PXP's crude under sales contracts that range from one year to four years in length. In October 2004, we further amended the PXP Marketing Agreement to exclude any newly acquired properties and to adjust the marketing fee to $0.15 per barrel for any new contracts entered into after January 1, 2005.

Due to Related Parties

The balance of amounts due to related parties at December 31, 2004 and 2003 was $32.9 million and $27.0 million, respectively, and was primarily related to crude oil purchased by us but not yet paid as of December 31 of each year.

Performance Option Plan

In connection with the transfer of a majority of our general partner interest in 2001, the owners of the general partner (other than PAA Management, L.P.) contributed an aggregate of 450,000 subordinated units (now converted into common units) to the general partner to provide a pool of units available for the grant of options to management and key employees. In that regard, the general partner adopted the Plains All American 2001 Performance Option Plan, pursuant to which options to purchase approximately 391,000 units have been granted. These options vest in 25% increments based upon achieving quarterly distribution levels on our units of $0.525, $0.575, $0.625 and $0.675 ($2.10, $2.30, $2.50 and $2.70, annualized). The first such level was reached, and 25% of the options vested, in 2002. The second level was reached, and an additional 25% of the options vested, in 2004. The options will vest in their entirety immediately upon a change in control (as defined in the grant agreements). The exercise price under the options was $22 per unit at the time of grant, declining over time in an amount equal to 80% of each quarterly distribution per unit. As of December 31, 2004, the exercise price was $15.91 per unit. The terms of future grants may differ from the existing grants. Because the units underlying the plan were contributed to the general partner, we will have no obligation to reimburse the general partner for the cost of the units upon exercise of the options. At December 31, 2004 approximately 388,000 units were outstanding.

Benefit Plan

Our general partner maintains a 401(k) defined contribution plan whereby it matches 100% of an employee's contribution (subject to certain limitations in the plan). For the years ended December 31, 2004, 2003 and 2002, the defined contribution plan matching expense was approximately $4.0 million, $2.6 million and $2.1 million, respectively. Similarly, PMC (Nova Scotia) Company maintains a group Registered Savings Plan and a Non Registered Employee Savings Plan for our Canadian employees. For the years ended December 31, 2004, 2003 and 2002, these plans had expense of approximately $1.0 million, $0.7 million and $0.4 million, respectively.

Note 10 Long-Term Incentive Plans

Our general partner has adopted the Plains All American GP LLC 1998 Long-Term Incentive Plan (the "1998 LTIP") for employees and directors of our general partner and its affiliates who perform services for us. Awards contemplated by the 1998 LTIP include phantom units and unit options. The 1998 LTIP currently permits the grant of phantom units and unit options covering an aggregate of 1,425,000 common units. The plan is administered by the Compensation Committee of our general partner's board of directors. Our general partner's board of directors has the right to alter or amend the 1998 LTIP or any part of the plan from time to time, including, subject to any applicable NYSE listing requirements, increasing the number of common units with respect to which awards may be granted; provided, however, that no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of such participant.

A phantom unit entitles the grantee to receive, upon the vesting of the phantom unit, a common unit (or cash equivalent, depending on the terms of the grant). As of December 31, 2004, aggregate outstanding grants of approximately 134,000 units have been made to employees, officers and directors of our general partner. The Compensation Committee may, in the future, make additional grants under the plan to employees and directors containing such terms as the Compensation Committee shall determine.

Common units to be delivered upon the vesting of grants may be common units acquired by our general partner in the open market or in private transactions, common units already owned by our general partner, or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the cost incurred in acquiring common units and any other costs incurred in settling obligations under the 1998 LTIP. In addition, the Partnership may issue up to 975,000 new common units to satisfy delivery obligations under the grants, less any common units issued upon exercise of unit options under the plan (see below). If we issue new common units upon vesting of the phantom units, the total number of common units outstanding will increase. The Compensation Committee, in its discretion, may grant tandem distribution equivalent rights ("DERs") with respect to phantom units. A DER entitles the grantee to a cash payment, either while the award is outstanding or upon vesting, equal to any cash distributions paid on a unit while the award is outstanding. There are no tandem equivalent distribution rights outstanding at this time under the 1998 LTIP.

Other than grants to directors, none of the phantom units vested until November 2003. Since that time, approximately 927,000 phantom units have vested. Including grants to directors, approximately 418,000 units have been purchased and delivered or issued in satisfaction of vesting, after payment of cash-equivalents and netting for taxes. Under generally accepted accounting principles, we are required to recognize expense when it is considered probable that phantom unit grants under our 1998 LTIP will vest. As a result, we recognized an expense of approximately $7.9 million and $28.8 million for the years ended December 31, 2004 and 2003, respectively.

The issuance of the common units upon vesting of phantom units is primarily intended to serve as a means of incentive compensation for performance. Therefore, no consideration is paid to us by the plan participants upon vesting and delivery of the common units.

Our 1998 LTIP currently permits the grant of options to purchase common units. No unit option grants have been made under the 1998 LTIP to date. However, the Compensation Committee may, in the future, make grants under the plan to employees and directors containing such terms as the committee shall determine, provided that unit options have an exercise price equal to the fair market value of the units on the date of grant.

In January 2005, our unitholders approved the 2005 Long-Term Incentive Plan (the "2005 LTIP"). The 2005 LTIP provides for awards to our employees and directors. Awards contemplated by the 2005 LTIP include phantom units, restricted units, unit appreciation rights and unit options, as determined by the Compensation Committee (each an "Award"). Up to 3,000,000 units may be issued in satisfaction of Awards. Certain Awards may also include DERs in the discretion of the Compensation Committee. Our general partner will be entitled to reimbursement by us for any costs incurred in settling obligations under the 2005 LTIP. Certain of these Awards could be considered a common stock equivalent and thus be dilutive to our earnings per unit from the time of their date of grant. In February 2005, our Board of Directors and Compensation Committee approved grants of approximately 1,900,000 phantom units (a substantial number of which include DERs) under the 2005 LTIP.

The issuance of the common units upon vesting of phantom units is primarily intended to serve as a means of incentive compensation for performance. Therefore, no consideration is paid to us by the plan participants upon vesting and delivery of the common units.

Note 11 Commitments and Contingencies

We lease certain real property, equipment and operating facilities under various operating and capital leases. We also incur costs associated with leased land, rights-of-way, permits and regulatory fees, the contracts for which generally extend beyond one year but can be cancelled at any time should they not be required for operations. Future non-cancellable commitments related to these items at December 31, 2004, are summarized below (in millions):

2005	$17.8
2006	$14.0
2007	$10.9
2008	$6.3
2009	$5.2
Thereafter	$13.7

Expenditures related to leases for 2004, 2003 and 2002 were $20.1 million, $13.4 million and $9.7 million, respectively.

Litigation

Export License Matter. In our gathering and marketing activities, we import and export crude oil from and to Canada. Exports of crude oil are subject to the "short supply" controls of the Export Administration Regulations ("EAR") and must be licensed by the Bureau of Industry and Security (the "BIS") of the U.S. Commerce Department. In 2002, we determined that we may have violated the terms of our licenses with respect to the quantity of crude oil exported and the end-users in Canada. Export of crude oil except as authorized by license is a violation of the EAR. In October 2002, we submitted to the BIS an initial notification of voluntary disclosure. The BIS subsequently informed us that we could continue to export while previous exports were under review. We applied for and received several new licenses allowing for export volumes and end users that more accurately reflect our anticipated business and customer needs. We also conducted reviews of new and existing contracts and implemented new procedures and practices in order to monitor compliance with applicable laws regarding the export of crude oil to Canada. As a result, we subsequently submitted additional information to the BIS in October 2003 and May 2004. In August 2004, we received a request from the BIS for additional information. We have responded to this and subsequent requests, and continue to cooperate fully with BIS officials. At this time, we have received neither a warning letter nor a charging letter, which could involve the imposition of penalties, and no indication of what penalties the BIS might assess. As a result, we cannot reasonably estimate the ultimate impact of this matter.

Alfons Sperber v. Plains Resources Inc., et al. On December 18, 2003, a putative class action lawsuit was filed in the Delaware Chancery Court, New Castle County, entitled Alfons Sperber v. Plains Resources Inc., et al. This suit, brought on behalf of a putative class of Plains All American Pipeline, L.P. common unitholders, asserted breach of fiduciary duty and breach of contract claims against us, Plains AAP, L.P., and Plains All American GP LLC and its directors, as well as breach of fiduciary duty claims against Plains Resources Inc. and its directors. The complaint sought to enjoin or rescind a proposed acquisition of all of the outstanding stock of Plains Resources Inc., as well as declaratory relief, an accounting, disgorgement and the imposition of a constructive trust, and an award of damages, fees, expenses and costs, among other things. This lawsuit has been settled in principle. The court has approved the settlement and, assuming no appeals are filed, the settlement will become final in March 2005.

Other. We, in the ordinary course of business, are a claimant and/or a defendant in various other legal proceedings. We do not believe that the outcome of these other legal proceedings, individually and in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows.

Note 12 Environmental Remediation

We currently own or lease properties where hazardous liquids, including hydrocarbons, are being or have been handled. As such, we could be required to remove or remediate hazardous liquids or associated generated wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial operations to prevent future contamination.

We maintain insurance of various types with varying levels of coverage that we consider adequate under the circumstances to cover our operations and properties. The insurance policies are subject to deductibles and retention levels that we consider reasonable and not excessive. Consistent with insurance coverage generally available in the industry, in certain circumstances our insurance policies provide limited coverage for losses or liabilities relating to gradual pollution, with broader coverage for sudden and accidental occurrences.

In addition, we have entered into indemnification agreements with various counterparties in conjunction with several of our acquisitions. Allocation of environmental liability is an issue negotiated in connection with each of our acquisition transactions. In each case, we make an assessment of potential environmental exposure based on available information. Based on that assessment and relevant economic and risk factors, we determine whether to negotiate an indemnity, what the terms of any indemnity should be (for example, minimum thresholds or caps on exposure) and whether to obtain insurance, if available. In some cases, we have received contractual protections in the form of environmental indemnifications from several predecessor operators for properties acquired by us that are contaminated as a result of historical operations. These contractual indemnifications typically are subject to specific monetary requirements that must be satisfied before indemnification will apply and have term and total dollar limits.

The acquisitions we completed in 2003 and 2004 include a variety of provisions dealing with the allocation of responsibility for environmental costs that range from no or limited indemnities from the sellers to indemnification from sellers with defined limitations on their maximum exposure. We have not obtained insurance for any of the conditions related to our 2003 acquisitions, and only in limited circumstances for our 2004 acquisitions.

For instance, in connection with the Link acquisition, we identified a number of environmental liabilities for which we received a purchase price reduction from Link. A substantial portion of these environmental liabilities are associated with the former Texas New Mexico ("TNM") pipeline assets. On the effective date of the acquisition, we and TNM entered into a cost-sharing agreement whereby, on a tiered basis, we will bear $11 million of the first $20 million of pre-May 1999 environmental issues. We will also bear the first $25,000 per site for new sites which were not identified at the time we entered into the agreement (capped at 100 sites). TNM will pay all costs in excess of $20 million (excluding the deductible for new sites). TNM's obligations are guaranteed by Shell Oil Products ("SOP"). We recorded a reserve for environmental liabilities of approximately $17.0 million in connection with the Link acquisition.

In connection with the acquisition of certain crude oil transmission and gathering assets from SOP in 2002, Shell purchased an environmental insurance policy covering known and unknown environmental matters associated with operations prior to closing. We are a named beneficiary under the policy, which has a $100,000 deductible per site, an aggregate coverage limit of $70 million, and expires in 2012. Shell has recently made a claim against the policy; however, we do not believe that the claim will substantially reduce our coverage under the policy.

In connection with our 1999 acquisition of Scurlock Permian LLC from MAP, we were indemnified by MAP for any environmental liabilities attributable to Scurlock's business or properties which occurred prior to the date of the closing of the acquisition. This indemnity applied to claims that exceeded $25,000 individually and $1.0 million in the aggregate. For the indemnity to apply, we were required to assert any claims on or before May 15, 2003. In conjunction with the expiration of this indemnity, we reached agreement with respect to MAP's remaining indemnity obligations. Under the terms of this agreement, MAP will continue to remain obligated for liabilities associated with two Superfund sites at which it is alleged that Scurlock Permian deposited waste oils. In addition, MAP paid us $4.6 million cash as satisfaction of its obligations with respect to other sites. During 2002, we had reassessed previous investigations and completed environmental studies related to environmental conditions associated with our 1999 acquisitions. As a result of that reassessment, we established an additional reserve of $1.2 million.

Other assets we have acquired or will acquire in the future may have environmental remediation liabilities for which we are not indemnified. We have in the past experienced and in the future will likely experience releases of crude oil into the environment from our pipeline and storage operations, or discover releases that were previously unidentified. Although we maintain a program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to environmental releases from our assets may substantially affect our business.

At December 31, 2004, our reserve for environmental liabilities totaled approximately $19.8 million (approximately $12.7 million of this reserve is related to liabilities assumed as part of the Link acquisition). Approximately $9.3 million of our environmental reserve is classified as current and $10.5 million is classified as long-term. At December 31, 2004, we have recorded receivables totaling approximately $6.3 million for amounts recoverable under insurance and from third parties under indemnification agreements.

In some cases, the actual cash expenditures may not occur for three to five years. We believe that this reserve is adequate, and in conjunction with our indemnification arrangements, should prevent remediation costs from having a material adverse effect on our financial condition, results of operations, or cash flows. Our estimates used in these reserves are based on all known facts at the time and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment and the possibility of existing legal claims giving rise to additional claims. Therefore, no assurances can be made that any costs incurred in excess of this reserve or outside of the indemnifications would not have a material adverse effect on our financial condition, results of operations, or cash flows.

Note 13 Quarterly Financial Data (Unaudited):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total[1]
	(in thousands, except per unit data)				
2004					
Revenues[3]	$ 3,804.6	$ 5,131.7	$ 5,867.0	$ 6,172.1	$ 20,975.5
Gross margin	59.7	64.8	74.0	65.7	264.2
Operating income	40.5	45.2	55.1	39.2	180.0
Income before cumulative effect of change in accounting principle	31.0	35.7	41.7	24.7	133.1
Net income	27.9	35.7	41.7	24.7	130.0
Basic and diluted income per limited partner unit before cumulative effect of change in accounting principle	0.49	0.54	0.59	0.32	1.94
Basic and diluted net income per limited partner unit	0.44	0.54	0.59	0.32	1.89
Cash distributions per common unit[2]	$ 0.563	$ 0.563	$ 0.578	$ 0.600	$ 2.30
2003					
Revenues[3]	$ 3,281.9	$ 2,709.2	$ 3,053.7	$ 3,545.0	$ 12,589.8
Gross margin	46.7	44.0	38.7	41.2	170.6
Operating income	33.6	31.9	21.0	11.6	98.2
Net income (loss)	24.4	23.4	11.9	(0.2)	59.4
Basic net income (loss) per limited partner unit	0.46	0.42	0.20	(0.03)	1.01
Diluted net income (loss) per limited partner unit	0.46	0.42	0.20	(0.03)	1.00
Cash distributions per common unit[2]	$ 0.538	$ 0.550	$ 0.550	$ 0.550	$ 2.19

(1) The sum of the four quarters does not equal the total year due to rounding.

(2) Distributions represent those declared and paid in the applicable period.

(3) Includes buy/sell transactions, see Note 2.

Note 14 Operating Segments

Our operations consist of two operating segments: (i) pipeline operations ("Pipeline Operations") and (ii) gathering, marketing, terminalling and storage operations ("GMT&S"). Through our pipeline segment, we engage in interstate and intrastate crude oil pipeline transportation and certain related margin activities. Through our GMT&S segment, we engage in purchases and resales of crude oil and LPG at various points along the distribution chain and we operate certain terminalling and storage assets. We believe that the combination of our terminalling and storage activities and gathering and marketing activities provides a counter-cyclical balance that has a stabilizing effect on our results of operations and cash flow. In a contango market (oil prices for future deliveries are higher than for current deliveries), we use our tankage to improve our gathering margins by storing crude oil we have purchased at lower prices in the current month for delivery at higher prices in future months. In a backwardated market (oil prices for future deliveries are lower than for current deliveries), we use and lease less storage capacity, but increased marketing margins (premiums for prompt delivery) provide an offset to this reduced cash flow.

We evaluate segment performance based on segment profit and maintenance capital. We define segment profit as revenues less (i) purchases, (ii) field operating costs, and (iii) segment general and administrative expenses. Maintenance capital consists of capital expenditures required either to maintain the existing operating capacity of partially or fully depreciated assets or to extend their useful lives. Capital expenditures made to expand our existing capacity, whether through construction or acquisition, are not considered maintenance capital expenditures. Repair and maintenance expenditures associated with existing assets that do not extend the useful life or expand the operating capacity are charged to expense as incurred. The following table reflects certain financial data for each segment for the periods indicated (note that each of the items in the following table excludes depreciation and amortization):

	Pipeline	GMT&S	Total
		(in millions)	
Twelve Months Ended December 31, 2004			
Revenues:			
External Customers (includes buy/sell revenues of $149.8, $11,247.0, and $11,396.8, respectively)	$ 752.9	$ 20,222.6	$ 20,975.5
Intersegment[a]	122.0	0.9	122.9
Total revenues of reportable segments	$ 874.9	$ 20,223.5	$ 21,098.4
Segment profit[c]	$ 157.2	$ 91.5	$ 248.7
Capital expenditures	$ 520.7	$ 131.5	$ 652.2
Total assets	$ 1,507.5	$ 1,652.9	$ 3,160.4
Non-cash SFAS 133 impact[b]	$	$ 1.0	$ 1.0
Maintenance capital	$ 8.3	$ 3.0	$ 11.3
Twelve Months Ended December 31, 2003			
Revenues:			
External Customers (includes buy/sell revenues of $166.2, $6,124.9, and $6,291.1, respectively)	$ 605.1	$ 11,984.7	$ 12,589.8
Intersegment[a]	53.5	0.9	54.4
Total revenues of reportable segments	$ 658.6	$ 11,985.6	$ 12,644.2
Segment profit[c]	$ 81.3	$ 63.1	$ 144.4
Capital expenditures	$ 211.9	$ 21.9	$ 233.8
Total assets	$ 1,221.0	$ 874.6	$ 2,095.6
Non-cash SFAS 133 impact[b]	$	$ 0.4	$ 0.4
Maintenance capital	$ 6.4	$ 1.2	$ 7.6
Twelve Months Ended December 31, 2002			
Revenues:			
External Customers (includes buy/sell revenues of $95.8, $4,140.8, and $4,236.7, respectively)	$ 462.4	$ 7,921.8	$ 8,384.2
Intersegment[a]	23.8		23.8
Total revenues of reportable segments	$ 486.2	$ 7,921.8	$ 8,408.0
Segment profit[c]	$ 70.7	$ 58.9	$ 129.6

	Pipeline	GMT&S	Total
Capital expenditures	$ 341.9	$ 23.3	$ 365.2
Non-cash SFAS 133 impact[(b)]	$	$ 0.3	$ 0.3
Maintenance capital	$ 3.4	$ 2.6	$ 6.0

Table continued on following page

(a) Intersegment sales were conducted at arms length.

(b) Amounts related to SFAS 133 are included in revenues and impact segment profit.

(c) The following table reconciles segment profit to consolidated income before cumulative effect of change in accounting principle (in millions):

	Year ended December 31,		
	2004	2003	2002
Segment profit	$ 248.7	$ 144.4	$ 129.6
Unallocated general and administrative expenses			(1.0)
Depreciation and amortization	(67.2)	(46.8)	(34.1)
Gain on sale of assets	0.6	0.6	
Impairment loss	(2.0)		
Interest expense	(46.7)	(35.2)	(29.1)
Interest income and other, net	(0.3)	(3.6)	(0.1)
Income before cumulative effect of change in accounting principle	$ 133.1	$ 59.4	$ 65.3

Geographic Data

We have operations in the United States and Canada. Set forth below are revenues and long lived assets attributable to these geographic areas (in millions):

	For the Year Ended December 31,		
Revenues	**2004**	**2003**	**2002**
United States (includes buy/sell revenues of $10,164.6, $5,621.6, and $3,715.5, respectively)	$ 17,499.5	$ 10,536.8	$ 6,941.7
Canada (includes buy/sell revenues of $1,232.2, $669.5, and $521.2, respectively)	3,476.0	2,053.0	1,442.5
	$ 20,975.5	$ 12,589.8	$ 8,384.2

	For the Year Ended December 31,	
Long-Lived Assets	**2004**	**2003**
United States	$ 1,670.8	$ 1,039.8
Canada	379.7	316.9
	$ 2,050.5	$ 1,356.7

Note 15 Subsequent Event

On February 25, 2005, we issued 575,000 common units to a subsidiary of Vulcan Energy Corporation. The sale price for the common units was $38.13 per unit resulting in net proceeds, including the general partner's proportionate capital contribution and expenses associated with the sale, of approximately $22.3 million. We intend to use the net proceeds from the private placement to fund a portion of our 2005 expansion capital program. Pending the incurrence of such expenditures, the net proceeds will be used to repay indebtedness under our revolving credit facilities.

Report of Independent Auditors

To the Board of Directors of the General Partner and partners of Plains AAP, L.P.:

In our opinion, the accompanying balance sheet presents fairly, in all material respects, the financial position of Plains AAP, L.P. at December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. This financial statement is the responsibility of Plains AAP, L.P.'s management; our responsibility is to express an opinion on this financial statement based on our audit. We conducted our audit of this statement in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the balance sheet is free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the balance sheet, assessing the accounting principles used and significant estimates made by management, and evaluating the overall balance sheet presentation. We believe that our audit of the balance sheet provides a reasonable basis for our opinion.

PricewaterhouseCoopers LLP

Houston, Texas
April 8, 2005

PLAINS AAP, L.P. BALANCE SHEET (in thousands)

	December 31, 2004
ASSETS	
Cash	$ 7
Investment in Plains All American Pipeline, L.P.	67,516
Total Assets	$ 67,523
LIABILITIES AND PARTNERS' CAPITAL	
LIABILITIES	
Performance Options Obligation	$ 4,061
COMMITMENTS AND CONTINGENCIES	
PARTNERS' CAPITAL	
Limited Partners	62,954
General Partner	508
Total Partners' Capital	63,462
Total Liabilities and Partners' Capital	$ 67,523

The accompanying notes are an integral part of this financial statement.

PLAINS AAP, L.P.

Notes to the Financial Statement

Note 1 Organization

Plains AAP, L.P. (the "Partnership") is a Delaware limited partnership, which was formed on May 21, 2001 and, through a series of transactions, was capitalized on June 8, 2001. Through this series of transactions, Plains Holdings II Inc. conveyed to the Partnership its general partner interest in Plains All American Pipeline, L.P. ("PAA") and subsequently sold a portion of its interest in the newly formed partnership to certain investors. The ownership interests in the Partnership (collectively, the "Partners") at December 31, 2004, are comprised of a 1% general partner interest held by Plains All American GP LLC (the "General Partner") and the following limited partner interests:

Plains Resources Inc. (a wholly owned subsidiary of Vulcan Energy Corporation)	43.560%
Sable Investments, L.P.	19.800%
KAFU Holdings, L.P.	16.253%
E-Holdings III, L.P.	8.910%
Mark E. Strome	2.113%
PAA Management L.P.	3.960%
Strome Hedgecap Fund, L.P.	1.055%
Wachovia Investors, Inc.	3.349%

As of December 31, 2004, we own a 2% general partner interest in PAA as well as incentive distribution rights, the ownership of which entitles us to receive incentive distributions if the amount that PAA distributes with respect to any quarter exceeds levels specified in the PAA partnership agreement. We also own a limited partner interest consisting of 446,875 common units (see Note 4). PAA is a publicly traded Delaware limited partnership, formed in 1998 and engaged in interstate and intrastate crude oil transportation, and crude oil gathering, marketing, terminalling and storage, as well as the marketing and storage of liquefied petroleum gas and other petroleum products (collectively, "LPG"), in the United States and Canada. PAA's operations can be categorized into two primary business activities:

Crude Oil Pipeline Transportation Operations. As of December 31, 2004, PAA owned approximately 15,000 miles of active gathering and mainline crude oil pipelines located throughout the United States and Canada. Its activities from pipeline operations generally consist of transporting crude oil for a fee, third party leases of pipeline capacity, barrel exchanges and buy/sell arrangements.

Gathering, Marketing, Terminalling and Storage Operations. As of December 31, 2004, PAA owned approximately 37 million barrels of active above-ground crude oil terminalling and storage facilities, including tankage associated with its pipeline systems. These facilities include a crude oil terminalling and storage facility at Cushing, Oklahoma. Cushing is one of the largest crude oil market hubs in the United States and the designated delivery point for NYMEX crude oil futures contracts. PAA utilizes its storage tanks to counter-cyclically balance its gathering and marketing operations and to execute various hedging strategies to stabilize profits and reduce the negative impact of crude oil market volatility. PAA's terminalling and storage operations also generate revenue at the Cushing Interchange and its other locations through a combination of storage and throughput charges to third parties. PAA's gathering and marketing operations include: the purchase of crude oil at the wellhead and the bulk purchase of crude oil at pipeline and terminal facilities, as well as foreign cargoes; the transportation of crude oil on trucks, barges and pipelines; the subsequent resale or exchange of crude oil at various points along the crude oil distribution chain; and the purchase of LPG from producers, refiners and other marketers, the storage of LPG at storage facilities owned by PAA or other parties and the sale of LPG to wholesalers, retailers and industrial end users.

Note 2 Summary of Significant Accounting Policies

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the balance sheet. These estimates include those made in determining the value of the vested options under our Performance Option Plan (see Note 6). Although management believes these estimates are reasonable, actual results could differ, and may differ materially from these estimates.

Investment in PAA

We account for our ownership investment in PAA in accordance with Accounting Principles Board Opinion No. 18, "The Equity Method of Accounting for Investments in Common Stock." We have the ability to exercise significant influence over PAA, but not control; and therefore, we account for the investment under the equity method (see Note 5). Changes in our ownership interest due to PAA's issuance of additional capital or other capital transactions that alter our ownership investment are recorded directly to partners' capital.

Stock-Based Compensation

The recipients of the options issued under the Performance Option Plan are employees of the General Partner. The options are options to purchase units of PAA. Thus, the accounting models prescribed by both Statement of Financial Accounting Standards ("SFAS") No. 123R (revised 2004) "Share-Based Payment", and Accounting Principles Board Opinion No. 25 "Accounting for Stock Issued to Employees" are not appropriate. We account for the options using an approach based on when the options will vest. Once the options vest, we adjust the accrual each period based on their fair market value as calculated using the "Black-Scholes Model" (see Note 6).

Income Taxes

No liability for U.S. or Canadian income taxes related to our operations is included in the accompanying financial statement because, as a partnership, we are not subject to Federal, State or Provincial income tax; and the tax effect of our activities accrues to the Partners. The Partners may be required to file U.S. Federal and State, as well as Canadian Federal and Provincial, income tax returns.

Note 3 Investment in PAA

Our investment in PAA at December 31, 2004, is approximately $67.5 million. The summarized financial information of PAA at December 31, 2004, is presented below (in millions):

Current assets	$	1,101.2
Non-current assets	$	2,059.2
Current liabilities	$	1,113.7
Long-term debt and other long-term liabilities	$	976.5
Partners' capital	$	1,070.2

At the date of inception, our investment in PAA exceeded our share of the underlying equity in the net assets of PAA by approximately $44.5 million. This excess is related to the fair value of PAA's crude oil pipelines and other assets at the time of inception and is amortized on a straight-line basis over their estimated useful life of 30 years. At December 31, 2004, the unamortized portion of this excess was approximately $35.7 million.

Note 4 Contribution of Subordinated Units

On June 8, 2001, certain of our limited partners contributed to us an aggregate of 450,000 subordinated units of PAA. In November 2003, 25% of these subordinated units converted into common units, and the remaining 75% converted into common units in February 2004. These 450,000 units (the "Option Units") (446,875 units remain after options were exercised) are intended for use in connection with an option plan pursuant to which certain members of the management of our general partner will, subject to the satisfaction of vesting criteria, have a right to purchase a portion of such Option Units. Until the exercise of the remainder of such options, we will continue to own and receive any distributions paid by PAA with respect to the Option Units. Any distributions we make as a result of the receipt of distributions on the Option Units will be paid to our limited partners in proportion to the original contribution of the Option Units.

The conversion of 75% of the subordinated units in February of 2004 resulted in an increase in our investment of approximately $1.5 million for the Partnership. This change of interest gain was non-cash and has been reflected in our partners' capital.

Note 5 Partners' Capital

We distribute all of our available cash, less reserves established by management, on a quarterly basis. Except as described in Note 4, distributions are paid to the partners in proportion to their percentage interest in the Partnership. Included in partners' capital is accumulated other comprehensive income of approximately $6.5 million related to our share of PAA's accumulated other comprehensive income (loss). Other comprehensive income (loss) is allocated based on each partner's ownership interest.

The General Partner manages the business and affairs of the Partnership. Except for situations in which the approval of the limited partners is expressly required by the Partnership agreement, or by nonwaivable provisions of applicable law, the General Partner has full and complete authority, power and discretion to manage and control the business, affairs and property of the Partnership, to make all decisions regarding those matters and to perform any and all other acts or activities customary or incident to the management of the Partnership's business, including the execution of contracts and management of litigation. The General Partner (or, in the case of PAA's Canadian operations, PMC (Nova Scotia) Company) employs all officers and personnel involved in the operation and management of PAA and its subsidiaries. PAA reimburses the General Partner for all expenses, including compensation expenses, related to such operation and management. The Partnership has no commitment or intent to fund cash flow deficits or furnish other financial assistance to PAA.

During the third quarter of 2004, PAA completed the issuance and sale of 4,968,000 Common Units at a public offering price of $33.25 per unit. In conjunction with that offering, we received additional investments from the Partners and made a contribution to PAA totaling approximately $3.4 million. In addition, PAA issued common units under its Long-Term Incentive Plan ("LTIP") in the third quarter of 2004. Because we hold PAA common units, we recognize a change of interest gain or loss at the time of each offering or issuance if the offering/issuance price is more or less than our average carrying amount per unit. Such gains or losses reflect the change in the book value of our equity in PAA compared to our proportionate share of the change in the underlying net assets of PAA due to the sale or issuance of the additional units. We recognized a gain of $0.5 million in our partners' capital related to the offering of common units and the issuance under PAA's LTIP.

Note 6 Performance Option Plan

In June 2001, the Performance Option Plan (the "Plan") was approved by the General Partner to grant options to purchase up to 450,000 Option Units of PAA to employees of the General Partner (see Note 4). Options to purchase 391,000 units have been issued under the Plan (including 16,000 options issued during the third quarter of 2004). The options were granted with a per unit exercise price of $22, less 80% of any per unit distribution on an Option Unit from June 2001, until the date of exercise. As of February 14, 2005, the exercise price has been reduced to $15.42 for distributions made since June 2001.

The options have a ten-year term and vest in 25% increments upon PAA achieving quarterly distribution levels as follows:

Vesting %	Quarterly Distribution Level	Annual Distribution Level
25%	$ 0.525	$ 2.10
25%	$ 0.575	$ 2.30
25%	$ 0.625	$ 2.50
25%	$ 0.675	$ 2.70

These options are considered performance awards and are accounted for at fair value upon vesting and are revalued at each financial statement date based on the "Black-Scholes Model." As of the date of declaration of the second quarter 2004 distribution (July 21, 2004) PAA attained the distribution level necessary for 50% of the options to vest. At December 31, 2004, an estimated fair value of $22.04 per unit resulted in a cumulative reduction of the Partners' capital accounts and corresponding increase in the Performance Options Obligation of approximately $4.1 million. No options expired or were forfeited or exercised during the period ended December 31, 2004. The options issued during the third quarter of 2004 will vest no earlier than the declaration date for the second quarter 2006 distribution. Thus, those options are not included in the obligation amounts. Future grants may include different vesting criteria.

The facts and assumptions used in the "Black-Scholes Model" at December 31, 2004, were as follows:

			Assumptions			
Options Outstanding	Percent Vested	Options Vested	Weighted Average Interest Rate	Weighted Average Expected Life	Weighted Average Expected Volatility	Weighted Average Expected Dividend Yield(1)
387,875	50%	184,375	3.59%	4.0	30.00%	1.81%

(1) Reflects 20% of anticipated dividend yield. The adjustment is to provide for the reduction in the exercise price of the options equal to 80% of distributions.

Note 7 Subsequent Events

Distribution

PAA declared cash distributions to the Partnership of $3.8 million ($0.8 million for its general partner interest and $3.0 million for its incentive distribution interest) for the fourth quarter of 2004. The distribution, which was declared on January 25, 2005, was received on February 14, 2005.

Private Placement of Common Units

On February 25, 2005, PAA issued 575,000 common units to a subsidiary of Vulcan Energy Corporation at a price of $38.13 per unit. In conjunction with that offering, we received additional investments from the Partners and made a contribution to PAA totaling approximately $0.4 million.

Performance Options/American Jobs Creation Act

On March 31, 2005, the Board of Directors of our general partner approved amendments to the Performance Option Plan and adjustments to the terms of outstanding unvested options. Such amendments and adjustments were designed to avoid or minimize any tax penalty that might otherwise be payable under the American Jobs Creation Act of 2004.

On March 31, 2005, grants for options to purchase 59,000 PAA common units were approved by the Board. Because the units underlying the Option Plan were contributed to us by certain of our owners, PAA will have no obligation to reimburse us for the cost of the units upon exercise of the options.

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

Plains All American Pipeline, L.P. ("PAA") is a publicly traded Delaware limited partnership engaged in interstate and intrastate crude oil transportation, and crude oil gathering, marketing, terminalling and storage, as well as the marketing and storage of liquefied petroleum gas and other petroleum products. The following unaudited pro forma financial statements are presented to give effect to the transactions described below:

The acquisition of the North American crude oil and pipeline operations of Link Energy LLC, ("Link Energy" and the "Link acquisition"). The acquisition price of approximately $326 million includes the assumption of liabilities and net working capital items and transaction and other acquisition costs. The acquisition closed and was effective on April 1, 2004 and has been accounted for using the purchase method of accounting.

The acquisition of Shell Pipeline Company LP's ("SPLC") interest in certain entities. The principal assets of the entities include interests in the Capline Pipe Line System, the Capwood Pipe Line System and the Patoka Pipe Line System (referred to in this report as "the SPLC acquisition"). The purchase price, including transaction and closing costs, was approximately $158.5 million. The acquisition closed and was effective on March 1, 2004. The acquisition has been accounted for using the purchase method of accounting.

The transactions described above are included in PAA's historical audited consolidated balance sheet as of December 31, 2004. Accordingly, an unaudited pro forma combined balance sheet is not presented. The historical financial statements of Link Energy and of the businesses acquired in the SPLC acquisition are not presented since the results of the transactions are reflected in PAA's historical consolidated statement of operations for a period of nine months or more. The unaudited pro forma statement of operations for the year ended December 31, 2004 is based upon the following:

1) the historical consolidated statement of operations of PAA for the year ended December 31, 2004;

2) the historical consolidated statement of operations of Link Energy for the three months ended March 31, 2004; and

3) the historical combined statement of operations for the businesses acquired in the SPLC acquisition for the two months ended February 29, 2004.

The unaudited pro forma combined statement of operations is not necessarily indicative of the results of the actual or future operations that would have been achieved had the transactions occurred at the date assumed (as noted below). The unaudited pro forma combined statement of operations should be read in conjunction with: i) the notes thereto; and ii) the historical audited financial statements of PAA for the year ended December 31, 2004.

The following unaudited pro forma combined statement of operations for the year ended December 31, 2004 has been prepared as if the transactions described above had taken place at the beginning of the period presented.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
UNAUDITED PRO FORMA COMBINED STATEMENT OF OPERATIONS
For the Year Ended December 31, 2004
(in thousands, except per unit data)

	Plains All American Historical	Link Energy Historical	SPLC Acquisition Historical	Pro Forma Acquisition Adjustments	Plains All American Pro Forma
REVENUES	$ 20,975,470	$ 40,682	$ 7,416	$ (465)(a)	$ 21,023,103
COSTS AND EXPENSES					
Purchases and related costs	20,424,572	8,081		(465)(a)	20,432,188
Field operating costs (excluding LTIP charge)	218,548	20,725	2,023		241,296
LTIP charge operations	918				918
General and administrative expenses (excluding LTIP charge)	75,735	18,514			94,249
LTIP charge general and administrative	7,013				7,013
Depreciation and amortization	67,241	5,060	874	(5,961)(b) 2,571 (c)	69,785
Total costs and expenses	20,794,027	52,380	2,897	(3,855)	20,845,449
Other, net		(20)			(20)
Gains on sales of assets	580	730(e)			1,310
Asset impairment	(2,000)				(2,000)
OPERATING INCOME	180,023	(10,988)	4,519	3,390	176,944
OTHER INCOME/(EXPENSE)					
Interest expense	(46,676)	(11,531)		(2,936)(d)	(61,143)
Interest and other income (expense), net	(211)	(24)			(235)
Income from continuing operations before cumulative effect of change in accounting principle	133,136	(22,543)	4,519	454	115,566
Cumulative effect of change in accounting principle	(3,130)				(3,130)
NET INCOME (LOSS) FROM CONTINUING OPERATIONS	$ 130,006	$ (22,543)	$ 4,519	$ 454	$ 112,436
NET INCOME FROM CONTINUING OPERATIONS LIMITED PARTNERS	$ 119,286				$ 102,067
NET INCOME FROM CONTINUING OPERATIONS GENERAL PARTNER	$ 10,720				$ 10,369
BASIC AND DILUTED NET INCOME FROM CONTINUING OPERATIONS PER LIMITED PARTNER UNIT					
Income from continuing operations before cumulative effect of change in accounting principle	$ 1.94				$ 1.66
Cumulative effect of change in accounting principle	(0.05)				(0.05)
Net income from continuing operations	$ 1.89				$ 1.61
BASIC AND DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	63,277				63,277

	Plains All American Historical	Link Energy Historical	SPLC Acquisition Historical	Pro Forma Acquisition Adjustments	Plains All American Pro Forma

See notes to unaudited pro forma combined financial statements

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
NOTES TO UNAUDITED PRO FORMA COMBINED FINANCIAL STATEMENT

Note 1 Acquisitions

Link Acquisition

The Link acquisition presented in this pro forma statement has been accounted for using the purchase method of accounting and the purchase price has been allocated in accordance with Statement of Financial Accounting Standards No. 141, "Business Combinations". The acquisition consists of the North American crude oil and pipeline operations of Link Energy. The purchase price of approximately $332 million includes cash paid of approximately $268 million (net of approximately $5.5 million subsequently returned to us from an indemnity escrow account) and approximately $64 million of net liabilities assumed and acquisition related costs. The acquisition closed and was effective on April 1, 2004. The purchase price allocation is set forth in the table below (in millions):

Cash paid for acquisition(1)	$	268.0
Fair value of net liabilities assumed:		
Accounts receivable(2)		409.4
Other current assets		1.8
Accounts payable and accrued liabilities(2)		(459.6)
Other current liabilities		(8.5)
Other long-term liabilities		(7.4)
Total net liabilities assumed		(64.3)
Total purchase price	$	332.3
Purchase price allocation		
Property and equipment	$	260.2
Inventory		3.4
Linefill		55.4
Inventory in third party assets		8.1
Goodwill		5.0
Other long term assets		0.2
Total	$	332.3

(1) Cash paid does not include the subsequent payment of various transaction and other acquisition related costs.

(2) Accounts receivable and accounts payable are gross and do not reflect the adjustment of approximately $250 million to net settle, based on contractual agreements with our counterparties.

SPLC Acquisition

The SPLC acquisition presented in this pro forma statement has been accounted for using the purchase method of accounting and the purchase price has been allocated in accordance with Statement of Financial Accounting Standards No. 141, "Business Combinations." The purchase consists of the acquisition of Shell Pipeline Company LP's ("SPLC") interest in certain entities. The principal assets of the entities include interests in certain businesses from Shell Pipeline Company, including its interests in the Capline Pipe Line System, the Capwood Pipe Line System and the Patoka Pipe Line System. The purchase price of approximately $158.5 million includes transaction and closing costs. The

acquisition closed and was effective on March 1, 2004. The purchase price allocation is as follows (in millions):

Crude oil pipelines and facilities	$	151.4
Crude oil storage and terminal facilities		5.7
Land		1.3
Office equipment and other		0.1
Total	$	