

PLAINS ALL AMERICAN PIPELINE LP
Form S-1
October 14, 2004

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As filed with the Securities and Exchange Commission on October 14, 2004

Registration No. 333-

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

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

*(State or Other Jurisdiction of
Incorporation or Organization)*

4610

*(Primary Standard Industrial
Classification Code Number)*

76-0582150

*(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

Houston, Texas 77002

(713) 646-4100

*(Name, Address, Including Zip Code, and Telephone Number,
Including Area Code, of Agent for Service)*

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Houston, Texas 77002

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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. ☒

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. ☐

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. ☐

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. ☐

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

CALCULATION OF REGISTRATION FEE

Title Of Each Class Of Securities To Be Registered	Amount to be Registered ⁽¹⁾	Proposed Maximum Offering Price Per Unit ⁽²⁾	Proposed Maximum Aggregate Offering Price ⁽¹⁾⁽²⁾	Amount of Registration Fee
Common Units representing limited partner interests ⁽¹⁾	3,245,700 units	\$36.40	\$118,143,480 ⁽²⁾	\$14,969 ⁽²⁾

(1) Includes the resale of 3,245,700 common units issuable upon the conversion of Class C common units into common units.

(2) Estimated solely for the purpose of determining the registration fee on the basis of the average high and low prices of the common units on the New York Stock Exchange on October 11, 2004.

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 October , 2004

PROSPECTUS

3,245,700 Common Units

Plains All American Pipeline, L.P.

Representing Limited Partner Interests

Up to 3,245,700 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 COMMISSION NOR ANY STATE SECURITIES COMMISSION 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 October , 2004

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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 3,245,700 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 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 liquefied petroleum gas and other 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. Several members of our existing management team founded this midstream crude oil business in 1992, and we completed our initial public offering in 1998.

We have operations in the United States and Canada, which 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 and expanding 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;

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 the Gulf Coast and Gulf of Mexico to take advantage of anticipated increases in the volume and qualities of crude oil produced in these areas; 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

You should carefully consider the following risk factors together with all of the other information included in this prospectus in evaluating an investment in us. If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected.

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 \$3.1 million. In addition, any production disruption from these fields due to production problems, transportation problems or other reasons would 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 as we purchase crude oil we establish a margin 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. This policy cannot, however, eliminate all price risks. For example, we engage in a controlled trading program for up to an aggregate of 500,000 barrels of crude oil. While this activity is monitored independently by our risk management function, it exposes us to price risks within predefined limits and authorizations. In addition, 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, 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 and to increase distributions to unitholders 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 and ability to raise distributions 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 credit 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 that will allow us to increase distributions to unitholders. 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:

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 make distributions to you.

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

Our operations involving the storage, treatment, processing, and transportation of liquid hydrocarbons including crude oil and are subject to stringent federal, state, and local laws and regulations governing the discharge of materials into the environment or otherwise relating to protection of the environment. 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.

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

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 10,000 barrel per day variance in the Basin Pipeline System, equivalent to an approximate 4% volume variance on that pipeline system, would change annualized segment profit by approximately \$1.0 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 terminalling and storage activities and gathering and marketing 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 per barrel variance in the aggregate average segment profit would have an approximate \$2.5 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 5,000 barrel per day decrease in barrels gathered by us would have an approximate \$1.0 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 counter-parties or that there will not be an unanticipated deterioration in their credit worthiness, which could have an adverse impact on us.

In those cases where 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. 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 June 30, 2004, pro forma for the third quarter equity and debt offerings, our total outstanding long-term debt was approximately \$797.1 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 and foreign currency restrictions and shortages 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. In addition, legal restrictions or shortages in currencies outside the U.S. may prevent us from converting sufficient local currency to enable us to

comply with our currency placement obligations not denominated in local currency or to meet our operating needs and debt service requirements.

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to entity-level taxation by states. If the IRS treats us as a corporation or we become subject to entity-level taxation for state tax purposes, it would substantially reduce our ability to make distributions to you.

If we were classified as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate rate. Treatment of us as a corporation would cause a material reduction in our anticipated cash flow, which would materially and adversely affect our ability to make distributions to you.

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. Imposition of such forms of taxation would reduce our cash flow.

We will be required to comply with Section 404 of the Sarbanes-Oxley Act for the first time.

The Sarbanes-Oxley Act of 2002 has imposed many new requirements on public companies regarding corporate governance and financial reporting. Among these is the requirement under Section 404 of the Act, beginning with our 2004 Annual Report, for management to report on our internal control over financial reporting and for our independent public accountants to attest to management's report. During 2003, we commenced actions to enhance our ability to comply with these requirements, including but not limited to the addition of staffing in our internal audit department, documentation of existing controls and implementation of new controls or modification of existing controls as deemed appropriate. We have continued to devote substantial time and resources to the documentation and testing of our controls, and to planning for and implementation of remedial efforts in those instances where remediation is indicated. At this point, we have no indication that management will be unable to favorably report on our internal controls nor that our independent auditors will be unable to attest to management's findings. Both we and our auditors, however, must complete the process (which we have never completed before), so we cannot assure you of the results. It is unclear what impact failure to comply fully with Section 404 or the discovery of a material weakness in our internal control over financial reporting would have on us, but presumably it could result in the reduced ability to obtain financing, the loss of customers, and additional expenditures to meet the requirements.

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. Because the owners of our general partner own more than

one-third of our outstanding units, these owners have the practical ability to prevent the removal of our general partner.

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:

if the holders, including the general partner and its affiliates, of at least 66²/₃% of the units vote to remove the general partner without cause, existing arrearages on the common units will be extinguished and the common units will no longer be entitled to arrearages if we fail to pay the minimum quarterly distribution in any quarter. Cause is narrowly defined to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding the general partner liable for actual fraud, gross negligence or willful or wanton misconduct in its capacity as our general partner.

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 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 and its affiliates;

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. Very little of our income will be qualifying income to a regulated investment company or mutual fund. 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 are registered as a tax shelter. This may increase the risk of an IRS audit of us or a unitholder.

We are registered with the IRS as a "tax shelter." Our tax shelter registration number is 99061000009. The IRS requires that some types of entities, including some partnerships, register as "tax shelters" in response to the perception that they claim tax benefits that the IRS may believe to be unwarranted. As a result, we may be audited by the IRS and tax adjustments could be made. Any unitholder owning less than a 1% profits interest in us has very limited rights to participate in the income tax audit process. Further, any adjustments in our tax returns will lead to adjustments in the unitholders' tax returns and may lead to audits of unitholders' tax returns and adjustments of items unrelated to us. You will bear the cost of any expense incurred in connection with an examination of your personal tax return.

Recently issued Treasury Regulations require taxpayers to report certain information on Internal Revenue Service Form 8886 if they participate in a "reportable transaction." Unitholders may be required to file this form with the IRS if we participate in a "reportable transaction." A transaction may be a reportable transaction based upon any of several factors. Unitholders are urged to consult with their own tax advisor concerning the application of any of these factors to their investment in our common units. Congress is considering legislative proposals that, if enacted, would impose significant penalties for failure to comply with these disclosure requirements. The Treasury Regulations also impose obligations on "material advisors" that organize, manage or sell interests in registered "tax shelters." As stated above, we have registered as a tax shelter, and, thus, one of our material advisors will be required to maintain a list with specific information, including unitholder names and tax identification numbers, and to furnish this information to the IRS upon request. Unitholders are urged to consult with their own tax advisor concerning any possible disclosure obligation with respect to their investment and should be aware that we and our material advisors intend to comply with the list and disclosure requirements.

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 September 30, 2004, there were 62,740,218 common units outstanding, held by approximately 340 holders of record, including common units held in street name. The common units are traded on the New York Stock Exchange under the symbol "PAA." An additional 1,307,190 Class B common units and 3,245,700 Class C common units were outstanding as of such date. The Class B common units are held by an affiliate of Plains Holdings Inc. and the Class C common units are held by six holders of record. The Class B common units and the Class C common units are *pari passu* with and have economic terms substantially similar to the common units but are not publicly traded. Holders of the Class B common units and the Class C common units have the right to demand a meeting of limited partners to vote on whether the Class B common units and Class C common units may be converted at the option of the holders into an equal number of common units. We anticipate that notice of the exercise of such right will be given on October 15, 2004.

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 October 11, 2004 was \$36.41 per common unit.

	Price Range		Cash Distributions per Unit ⁽¹⁾
	High	Low	
2002			
First Quarter	\$ 26.79	\$ 23.60	\$ 0.5250
Second Quarter	27.30	24.60	0.5375
Third Quarter	26.38	19.54	0.5375
Fourth Quarter	24.44	22.04	0.5375
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	(2)
Fourth Quarter (through October 11, 2004)	36.99	35.76	(2)

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

(2) The distributions attributable to the third and fourth quarters of 2004 have not yet 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, 2003, 2002, 2001, 2000 and 1999 and from our unaudited financial statements as of and for the six months ended June 30, 2004 and 2003. 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.

	Six Months Ended June 30,		Year Ended December 31,				
	2004	2003	2003	2002	2001	2000	1999
(in millions except per unit data)							
Statement of operations data:							
Revenues	\$ 8,936.4	\$ 5,991.1	\$ 12,589.8	\$ 8,384.2	\$ 6,868.2	\$ 6,641.2	\$ 10,910.4
Cost of sales and field operations (excluding LTIP charge)	8,782.2	5,878.2	12,366.6	8,209.9	6,720.9	6,506.5	10,800.1
Unauthorized trading losses and related expenses						7.0	166.4
Inventory valuation adjustment					5.0		
LTIP charge operation ⁽⁴⁾	0.5		5.7				
General and administrative expenses (excluding LTIP charge)	35.1	25.2	50.0	45.7	46.6	40.8	23.2
LTIP charge general and administrative ⁽¹⁾	3.7		23.1				
Depreciation and amortization	29.1	22.2	46.8	34.0	24.3	24.5	17.3
Restructuring expense							1.4
Total costs and expenses	8,850.6	5,925.6	12,492.3	8,289.6	6,796.8	6,578.8	11,008.4
Gain on sale of assets			0.6		1.0	48.2	16.4
Operating income	85.7	65.4	98.2	94.6	72.4	110.6	(81.6)
Interest expense	(19.5)	(17.7)	(35.2)	(29.1)	(29.1)	(28.7)	(21.1)
Interest income and other, net ⁽²⁾	0.5		(3.6)	(0.2)	0.4	(4.4)	(0.6)
Income (loss) from continuing operations before cumulative effect of change in accounting principle ⁽¹²⁾	\$ 66.7	\$ 47.7	\$ 59.4	\$ 65.3	\$ 43.7	\$ 77.5	\$ (103.4)
Basic net income (loss) per limited partner unit before cumulative effect of change in accounting principle ⁽²⁾⁽¹²⁾	\$ 1.03	\$ 0.87	\$ 1.01	\$ 1.34	\$ 1.12	\$ 2.13	\$ (3.21)
Diluted net income (loss) per limited partner unit before cumulative effect of change in accounting principle ⁽²⁾⁽¹²⁾	\$ 1.03	\$ 0.87	\$ 1.00	\$ 1.34	\$ 1.12	\$ 2.13	\$ (3.21)
Basic weighted average number of limited	60.0	51.2	52.7	45.5	37.5	34.4	31.6

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	Six Months Ended June 30,		Year Ended December 31,				
partner units outstanding							
Diluted weighted average number of limited partner units outstanding	60.0	51.2	53.4	45.5	37.5	34.4	31.6
Balance sheet data (at end of period):							
Total assets	2,682.0	1,710.4	2,095.6	1,666.6	1,261.2	885.8	1,223.0
Total long-term debt ⁽³⁾⁽⁴⁾	934.8	526.5	519.0	509.7	354.7	320.0	424.1
Total debt ⁽⁴⁾	956.8	544.5	646.2	609.0	456.2	321.3	482.8
Partners' capital	865.6	600.8	746.7	511.6	402.8	214.0	193.0
Other data:							
Maintenance capital expenditures	\$ 3.1	\$ 4.2	\$ 7.6	\$ 6.0	\$ 3.4	\$ 1.8	\$ 1.7
Net cash provided by (used in) operating activities ⁽⁵⁾	147.1	204.8	115.3	185.0	(16.2)	(33.5)	(71.2)
Net cash provided by (used in) investing activities ⁽⁵⁾	(474.6)	(139.8)	(272.1)	(374.9)	(263.2)	211.0	(186.1)
Net cash provided by (used in) financing activities	334.0	63.0	157.2	189.5	279.5	(227.8)	305.6
Declared distributions per limited partner unit ⁽⁶⁾⁽⁷⁾⁽⁸⁾	1.13	1.09	2.19	2.11	1.95	1.83	1.59

Table continued on
following page.

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Operating Data:

Volumes (thousands of barrels per day)⁽⁹⁾

Pipeline segment:

Tariff activities							
All American	57	61	59	65	69	74	103
Link acquisition	185	N/A	N/A	N/A	N/A	N/A	N/A
Capline	112	N/A	N/A	N/A	N/A	N/A	N/A
Basin	273	245	263	93	N/A	N/A	N/A
Other domestic ⁽¹⁰⁾	408	26	299	219	144	130	61
Canada	250	181	203	187	132	N/A	N/A
Pipeline margin activities	73	81	78	73	61	60	54
Total	1,358	829	902	637	406	264	218

Gathering, marketing, terminalling and storage segment:

Lease gathering	550	430	437	410	348	262	265
Bulk purchases ⁽¹¹⁾	135	78	90	68	46	28	138
Total	685	508	527	478	394	290	403
LPG sales	40	35	38	35	19	N/A	N/A

(1) Compensation expense related to our Long Term Incentive Plan ("LTIP"), see "Management 1998 Long-Term Incentive Plan Restricted Unit Plan."

(2) The 2000 and 1999 periods include \$15.1 million and \$1.5 million, respectively related to losses on the early extinguishment of debt previously classified as an extraordinary item. Effective with the issuance 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 April 2002, such items should now be shown as impacting income from continuing operations. As a result of this reclassification, basic and diluted net income (loss) per limited partner unit before cumulative effect of change in accounting principle for 2000 and 1999 were reduced by \$0.44 and \$0.05, respectively. In addition, effective with the issuance of 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," the 2000 amount was further reduced by \$0.07.

(3) Includes current maturities of long-term debt of \$9.0 million, \$3.0 million, and \$50.7 million at December 31, 2002, 2001 and 1999, respectively, classified as long-term because of our ability and intent to refinance these amounts under our long-term revolving credit facilities.

(4) The 1999 amount includes a \$114.0 million note payable to our former general partner.

(5) In conjunction with the change in accounting principle we adopted January 1, 2004, 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 as cash flows from operating activities.

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

(7) 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.

(8) 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 7 "Partners' Capital and Distributions" in the "Notes to the Consolidated Financial Statements."

(9) 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.

(10)

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We have decreased the number of barrels previously disclosed in the "Other domestic" line for the 2002 period by approximately 9,000. The adjustment reflects an elimination of the duplication caused by reflecting volumes that were transported by truck in addition to being transported by pipeline. We believe this elimination more accurately reflects our business on this pipeline.

(11)

We have decreased the number of barrels previously disclosed in the "Bulk purchases" line for the 2002 period by approximately 12,000. The adjustment reflects an elimination of crude oil volumes improperly classified as bulk purchases.

(12)

Income from continuing operations before cumulative effect of change in accounting principle pro forma for the impact of changing 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. The change had no impact on 1999.

**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 and should be read in conjunction with our historical consolidated financial statements and accompanying notes included elsewhere in this prospectus.

Our discussion and analysis includes the following:

Executive Summary

Acquisitions

Critical Accounting Policies and Estimates

Recent Accounting Pronouncements

Change in Accounting Principle

Results of Operations

Outlook

Liquidity and Capital Resources

Off-Balance Sheet Arrangements

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 liquefied petroleum gas and other 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.

We are one of the largest midstream crude oil companies in North America. As of June 30, 2004, we owned approximately 15,000 miles of crude oil pipelines, approximately 37 million barrels of terminalling and storage capacity and a full complement of truck transportation and injection assets. Currently, we handle an average of over 2.6 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 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.

Overview of Operating Results

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Six Months Ended June 30, 2004. During the first six months of 2004, we recognized net income and earnings per limited partner unit of \$63.5 million and \$0.98, respectively, which was a 33% and 13% increase, respectively, over the first six months of 2003. The results for the first six months of 2004 compared to the first six months of 2003 include significant contributions from the acquisitions completed during the second half of 2003 and the first half of 2004. In addition, the 2004 results

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include a non-cash gain of approximately \$0.5 million resulting from the mark-to-market of open derivative instruments pursuant to Statement of Financial Accounting Standard No. 133, as amended ("SFAS 133"), while the first six months of 2003 includes a non-cash gain of approximately \$1.1 million.

Significant events in the first six months of 2004 that affected our results of operations included the following:

We acquired all of the North American crude oil and pipeline operations of Link Energy LLC ("Link") for approximately \$326 million. The acquisition was initially funded with cash on hand, borrowings under a new \$200 million, 364-day credit facility and borrowings under our existing revolving credit facilities. In connection with this acquisition, on April 15, 2004, we completed the private placement of 3,245,700 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, generating aggregate proceeds of approximately \$101 million, including the general partner's proportionate contribution. See "Acquisitions" and "Liquidity and Capital Resources."

We changed our method of accounting for pipeline linefill in third party assets resulting in a cumulative effect of change in accounting principle of \$3.1 million. 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. 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, will be 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 will reclassify linefill in third party assets not expected to be liquidated within the succeeding twelve months out of "Inventory" (a current asset) and into "Inventory in Third Party Assets" (a long-term asset) at average cost, which is now reflected as a separate line item within other assets on the consolidated balance sheet.

Under generally accepted accounting principles, we are required to recognize an expense when vesting of LTIP units becomes probable as determined by management. Our results of operations include a charge of \$4.2 million in the six months ended June 30, 2004. This charge is comprised of three components as follows. Approximately \$1.1 million of the charge related to phantom units that vested in May 2004. We had previously concluded at December 31, 2003, that these units were probable of vesting and had accrued a portion of the related obligation at that time. This charge also relates to the amortization of service period requirements and adjustments to the assumptions used in our estimate. Approximately \$3.1 million of the charge related to the probable vesting of phantom units, the bulk of which vested in August 2004.

Fiscal Year 2003. During 2003:

We enhanced and strengthened our overall capital structure and maintained substantial liquidity through changes in our credit facility, a series of equity issuances and a ten-year senior notes issuance. During the year, we successfully syndicated a new \$950 million credit facility that significantly reduced our incremental borrowing costs by reducing our LIBOR-based credit spread by over 100 basis points. As a result of this transaction, we recognized a non-cash charge of approximately \$3.3 million associated with the write-off of unamortized debt issue costs. In addition, we raised approximately \$250 million of equity capital in three separate transactions and we accessed the debt capital markets by issuing \$250 million of ten-year senior notes at an effective yield of 5.7 percent.

We satisfied the final requirements of the multi-year subordination tests under our partnership agreement that caused the conversion of our subordinated units into common units, thus

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simplifying our capital structure. The conversion also triggered the vesting in 2003 and 2004 of a portion of the outstanding phantom units under our Long-Term Incentive Plan. During 2003, we accrued a portion of the estimated expense associated with the anticipated 2004 vesting, resulting in a charge of approximately \$28.8 million.

We completed a total of ten accretive and strategic transactions for aggregate consideration of \$159.5 million. An integral component of our business strategy and growth objective is to acquire assets and operations that are strategic and complementary of our existing operations. Our historical acquisition activity is discussed under " Acquisitions" below.

We realized year over year growth in segment profit from both our pipeline operations segment and our GMT&S segment, including the impact of the charges discussed above. This growth was primarily driven by (i) the impact of the current year acquisitions subsequent to their acquisition during 2003 and the inclusion of a full year contribution from those assets that we acquired during 2002 coupled with (ii) the positive results in volatile market conditions of our counter-cyclically balanced activities in our GMT&S segment.

We raised our distribution level on our limited partner units on two separate occasions by a total of \$0.10 per unit to \$2.25 per unit on an annualized basis.

Prospects for the Future. We believe 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 with our relatively stable, fee-based pipeline assets enables us to generate stable financial results in an industry that is highly cyclical.

During fiscal year 2004, we have further strengthened our position by expanding our asset base through acquisition and internal growth projects. We will continue to pursue the purchase of assets, and we will also continue to initiate projects designed to optimize crude oil flows in the areas in which we operate. 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" and "Forward-Looking Statements" for further discussion of these items.

Acquisitions

We completed a number of acquisitions 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

During the first six months of 2004, we have completed several acquisitions for aggregate consideration of approximately \$506.1 million. The aggregate consideration includes cash paid, estimated transaction costs and assumed liabilities and net working capital items. The following table

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summarizes acquisitions (in millions) for the first six months of 2004, and a description of each of these follows the table:

Acquisition	Effective Date	Acquisition Price	Operating Segment
Capline and Capwood Pipeline Systems	03/01/04	\$ 158.5	Pipeline
Link Energy LLC	04/01/04	326.1	Pipeline/GMT&S
Cal Ven Pipeline System	05/01/04	19.0	Pipeline
Other ⁽¹⁾	06/01/04	2.5	Pipeline
Total 2004 Acquisitions through June 30, 2004		\$ 506.1	

(1)

Includes several acquisitions that had an immaterial impact on results of operations for the period.

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. 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
Total	\$ 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 \$326 million, including \$268 million of cash (net of approximately \$5.5 million subsequently returned to PAA from an indemnity escrow account) and approximately \$58 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 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):

Fair value of assets acquired:	
Property and equipment	\$ 256.3
Inventory	1.1
Linefill	48.4
Inventory in third party assets	15.1
Goodwill	5.0
Other long term assets	0.2
	<hr/>
Subtotal	326.1
Accounts receivable	405.4
Other current assets	1.8
	<hr/>
Subtotal	407.2
	<hr/>
Total assets acquired	733.3
Fair value of liabilities assumed:	
Accounts payable and accrued liabilities	(448.9)
Other current liabilities	(8.5)
Other long-term liabilities	(7.4)
	<hr/>
Total liabilities assumed	464.8
	<hr/>
Cash paid for acquisition ⁽¹⁾	\$ 268.5
	<hr/>

(1) Cash paid is net of \$5.5 million subsequently returned to us from an indemnity escrow account and does not include the subsequent payment of various transaction and other acquisition related costs.

We are in the process of evaluating certain estimates made in the purchase price allocation; thus, the allocation is subject to refinement. In addition, we anticipate making capital expenditures of approximately \$20.0 million (\$9.0 million of which will be spent in 2004) to upgrade certain of the assets and comply with certain regulatory requirements.

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. 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. Representatives from the Antitrust and Civil Medicaid Fraud Division of the Texas AG indicated their investigation was prompted by complaints received from allegedly interested industry parties regarding the potential impact on competition in the Permian Basin area of West Texas. We understand that similar complaints have been received by the Federal Trade Commission, and that, consistent with federal-state protocols for conducting joint merger investigations, appropriate federal and state antitrust authorities are coordinating their activities. In connection with the April notice and again in June 2004, the Texas AG requested information from us. We have complied with these requests and are cooperating fully with the antitrust enforcement authorities.

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.

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 subsequent to 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 ⁽¹⁾	05/05/03	2.9	Pipeline
South Louisiana Assets ⁽²⁾	06/01/03	13.4	Pipeline/GMT&S
Alto Storage Facility	06/01/03	8.5	GMT&S
Iraan to Midland Pipeline System	06/30/03	17.6	Pipeline
ArkLaTex Pipeline System	10/01/03	21.3	Pipeline/GMT&S
South Saskatchewan Pipeline System	11/01/03	47.7	Pipeline
Atchafalaya Pipeline System ⁽³⁾	12/01/03	4.4	Pipeline
Total 2003 Acquisitions		\$ 159.5	

(1) Consists of an 8.8% undivided interest.

(2) Includes a 33.3% interest in Atchafalaya Pipeline L.L.C. as well as other assets.

(3) Includes two acquisitions each for 33.3% interests in Atchafalaya Pipeline L.L.C., that when combined with the acquisition referenced in (2) above, results in a total ownership of 100%.

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. In addition, we believe that the Basin Pipeline System is poised to benefit from potential shut-downs of refineries and other pipelines due to the shifting market dynamics in the West Texas area. The Rancho Pipeline System was taken out of service in March 2003, pursuant to the operating agreement. See "Business Acquisitions and Dispositions Shutdown and Partial 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.

2001 Acquisitions

CANPET Energy Group. 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.

At the time of the acquisition, CANPET's activities consisted of gathering approximately 75,000 barrels per day of crude oil and marketing an average of approximately 26,000 barrels per day of natural gas liquids or LPGs. The principal assets acquired include a crude oil handling facility, a 130,000-barrel tank facility, LPG facilities, existing business relationships and operating inventory. The acquired assets are part of our strategy to establish a Canadian operation that complements our operations in the United States. The purchase price, as adjusted for post-closing adjustments of \$1.0 million, was allocated as follows (in millions):

Inventory	\$ 28.1
Goodwill	35.4
Intangible assets (contracts)	1.0
Pipeline linefill	4.3
Crude oil gathering, terminalling and other assets	5.1
	<hr/>
Total	\$ 73.9
	<hr/>

Murphy Oil Company Ltd. Midstream Operations. In May 2001, we completed the acquisition of substantially all of the Canadian crude oil pipeline, gathering, storage and terminalling assets of Murphy Oil Company Ltd. for approximately \$158.4 million in cash after post-closing adjustments, including financing and transaction costs (the "Murphy acquisition"). Initial financing for the acquisition was provided through borrowings under our credit facilities. The purchase price included \$6.5 million for excess inventory in the pipeline systems. The principal assets acquired include approximately 560 miles of crude oil and condensate mainlines (including dual lines on which condensate is shipped for blending purposes and blended crude is shipped in the opposite direction) and associated gathering and lateral lines, approximately 1.1 million barrels of crude oil storage and terminalling capacity located primarily in Kerrobert, Saskatchewan, approximately 254,000 barrels of pipeline linefill and tank inventories, and 121 trailers used primarily for crude oil transportation. The

acquired assets are part of our strategy to establish a Canadian operation that complements our operations in the United States.

Murphy agreed to continue to transport production from fields previously delivering crude oil to these pipeline systems, under a long-term contract. At the time of acquisition, these volumes averaged approximately 11,000 barrels per day. Total volumes transported on the pipeline system in 2001 were approximately 223,000 barrels per day of light, medium and heavy crudes, as well as condensate.

The purchase price, as adjusted post-closing, was allocated as follows (in millions):

Crude oil pipeline, gathering and terminal assets	\$	148.0
Pipeline linefill		7.6
Networking capital items		2.0
Other property and equipment		0.5
Other assets, including debt issue costs		0.3
<hr/>		
Total	\$	158.4
<hr/>		

Other 2001 Acquisitions. In December 2001, we consummated the acquisition of the Wapella Pipeline System from private investors for approximately \$12.0 million, including transaction costs. The entire purchase price was allocated to property and equipment. The system further expands our market in Canada.

Critical Accounting Policies and Estimates

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 8% 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 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 insurance claims, and the possibility of existing legal claims giving rise to additional claims. Our estimates and contingent liability accruals are increased or decreased as additional information is obtained or resolution is achieved. A variance of 10% in our aggregate estimate would have an approximate \$3.0 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

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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

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:

	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 cost 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, will be 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 will 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 six months ended June 30, 2004 and the consolidated balance sheet as of June 30, 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 second quarter of 2003 was not material to net income or net income per basic and diluted limited partner unit. The pro forma impact for the first half of 2003 would have been an increase to net income of approximately \$1.8 million (\$0.04 per basic and diluted limited partner unit) resulting in pro forma net income of \$49.6 million and pro forma net income per limited partner unit (basic and diluted) of \$0.91.

In conjunction with this change in accounting principle, we will classify 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 as cash flows from operating activities. Accordingly, the statement of cash flows for the six months ended June 30, 2003 has been revised to reclassify the cash paid for linefill in assets owned from operating activities to investing activities. The effect of the reclassification was an increase to net cash provided by operating activities and net cash used in investing activities of \$28.5 million for the six months ended June 30, 2003. As a result of this change in classification, net cash provided by operating activities for the years ended December 31, 2003 and 2002 would increase 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 would increase to \$272.1 million from \$225.3 million and \$374.8 million from \$363.8 million, respectively. In addition, net cash used in operating activities for the year ended December 31, 2001 would decrease from \$30 million to \$16.2 million and net cash used in investing activities would increase to \$263.2 million from \$249.5 million. This change in classification had no impact on the years ended 2000 and 1999.

Results of Operations

Analysis of Operating Segments

Our operations consist of two operating segments: (1) our Pipeline Operations, through which we engage in interstate and intrastate crude oil pipeline transportation and certain related merchant activities; and (2) our GMT&S Operations, through which we engage in purchases and resales of crude oil and LPG at various points along the distribution chain and the operation of certain terminalling and storage assets.

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.

Pipeline Operations

As of June 30, 2004 and December 31, 2003, we owned approximately 15,000 miles and 7,000 miles, respectively, of 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.

Gathering, Marketing, Terminalling and Storage Operations

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 without significant changes to our margins related to those purchases and sales. For example, our revenues from gathering and marketing activities increased approximately 51% in the first half of 2004 compared to the first half of 2003, while our segment profit decreased approximately 3% in the same period. Approximately 55% of the increase in revenues related to increased sales volumes and the remaining 45% of the increase resulted from higher average prices in the 2004 period. The increase in sales volume primarily related to increased lease gathered barrels resulting primarily from the Link acquisition.

Generally, we expect our segment profit to increase or decrease directionally with increases or decreases in lease gathered volumes and LPG sales volumes. However, although the Link acquisition increased lease gathered barrels and revenues, there was not a corresponding contribution to segment profit as the lease gathered barrels primarily support the pipeline operations. Although we believe that the combination of our lease gathering business and our storage assets provides a counter-cyclical balance, which 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.

As of June 30, 2004 and December 31, 2003, we owned approximately 37 million and 24 million, respectively, barrels of 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 12.6 million barrels of our 37.0 million barrels of tankage is used primarily in our GMT&S Operations 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 and lease 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.

During the first half of 2004, market conditions were generally favorable as the market was in relatively strong backwardation and experienced periods of volatility. The NYMEX benchmark price of crude ranged from \$42.38 to \$32.20 during the period. The market conditions in the first half of 2003 were more favorable as there was relatively high volatility and strong backwardation throughout the period. Additionally, cold weather during the first quarter of 2003 resulted in increased sales and higher margins in our LPG activities. During the first half of 2003, the NYMEX benchmark price of crude oil ranged from \$39.99 to \$25.04.

Six Months Ended June 30, 2004 and 2003

For the six months ended June 30, 2004, we reported consolidated net income of \$63.6 million on total revenues of \$8.9 billion compared to net income for the same period in 2003 of \$47.7 million on total revenues of \$6.0 billion. The following table reflects our results of operations and maintenance

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capital for each segment (note that each of the items in the following table excludes depreciation and amortization):

	Pipeline	GMT&S
	(in millions)	(in millions)
Six Months Ended June 30, 2004⁽¹⁾		
Revenues	\$ 412.1	\$ 8,572.6
Purchases	(269.6)	(8,464.2)
Field operating costs (excluding LTIP charge)	(51.2)	(45.7)
LTIP charge operations	(0.1)	(0.4)
Segment G&A expenses (excluding LTIP charge) ⁽²⁾	(16.3)	(18.7)
LTIP charge general and administrative	(1.7)	(2.0)
Segment profit	\$ 73.2	\$ 41.6
Noncash SFAS 133 impact ⁽³⁾	\$	\$ 0.5
Maintenance capital	\$ 2.1	\$ 1.0
Six Months Ended June 30, 2003⁽¹⁾		
Revenues	\$ 324.8	\$ 5,689.3
Purchases	(243.6)	(5,591.9)
Field operating costs	(27.7)	(38.0)
Segment G&A expenses ⁽²⁾	(9.1)	(16.1)
Segment profit	\$ 44.4	\$ 43.3
Noncash SFAS 133 impact ⁽³⁾	\$	\$ 1.1
Maintenance capital	\$ 3.8	\$ 0.4

(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.

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

	Six Months Ended June 30,	
	2004	2003
Operating Results (in millions) ⁽¹⁾		
Revenues		
Tariff activities	\$ 130.9	\$ 72.1
Pipeline margin activities	281.2	252.7
Total pipeline operations revenues	412.1	324.8
Costs and Expenses		
Pipeline margin activities purchases	(269.6)	(243.6)
Field operating costs (excluding LTIP charge)	(51.2)	(27.7)
LTIP charge operations	(0.1)	
Segment G&A expenses (excluding LTIP charge) ⁽²⁾	(16.3)	(9.1)
LTIP charge general and administrative	(1.7)	
Segment profit	\$ 73.2	\$ 44.4
Maintenance capital	\$ 2.1	\$ 3.8
Average Daily Volumes (thousands of barrels per day) ⁽³⁾		
Tariff activities		
All American	57	61
Basin	273	245
Link acquisition	185	N/A
Capline	112	N/A
Other domestic	408	261
Canada	250	181
Total tariff activities	1,285	748
Pipeline margin activities	73	81
Total	1,358	829

(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.

Total average daily volumes transported were approximately 1.4 million barrels per day and 0.8 million barrels per day for the six months ended June 30, 2004 and 2003, respectively. The increase relates to our tariff activities. As discussed above, we have completed a number of

acquisitions during

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2004 and 2003 that have impacted our results of operations. The following table reflects our total average daily volumes from our tariff activities by year of acquisition for comparison purposes:

	Six Months Ended June 30,	
	2004	2003
	(thousands of barrels per day)	
Tariff activities⁽¹⁾		
2004 acquisitions	396	
2003 acquisitions	166	33
All other pipeline systems	723	715
Total tariff activities average daily volumes	1,285	748

(1) 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.

Average daily volumes from our tariff activities increased 0.5 million barrels per day to approximately 1.3 million barrels per day. Almost all of the increase in the current year quarter is due to volumes transported on the pipelines acquired in 2004 and 2003. Volumes on all other pipeline systems were relatively unchanged.

Total revenues from our pipeline operations were approximately \$412.1 million and \$324.8 million for the six months ended June 30, 2004 and 2003, respectively. An increase in revenues from tariff activities accounted for \$58.8 million of the increase. Additionally, our margin activities increased by approximately \$28.5 million in the first half of 2004. This increase was related to higher average prices for crude oil sold and transported on our SJV gathering system in the 2004 period as compared to the 2003 period, partially offset by lower buy/sell volumes. 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. Volumes transported on the SJV system have decreased from the 2003 period. This is primarily related to a normalizing of volumes transported in the first quarter of 2004 as the first quarter of 2003 included additional shipments that typically move on other pipelines. These volumes shifted to the SJV system in 2003 because of maintenance being performed on a refinery during that time period.

Revenues from our tariff activities increased approximately 82% or \$58.8 million. The following table reflects our revenues from our tariff activities by year of acquisition for comparison purposes:

	Six Months Ended June 30,	
	2004	2003
	(in millions)	
Tariff activities revenues⁽¹⁾		
2004 acquisitions	\$ 41.9	\$
2003 acquisitions	17.3	4.0
All other pipeline systems	71.7	68.1
Total tariff activities average daily volumes	\$ 130.9	\$ 72.1

(1)

Revenues include intersegment amounts.

The increase in the first half of 2004 is predominately related to the inclusion of \$26.6 million of revenues from the pipelines acquired in the Link acquisition and \$15.3 of revenues from other businesses acquired in 2004. Revenues from pipeline systems acquired in 2003 have increased to \$17.3 million from \$4.0 million. The increase is primarily the result of the inclusion in the first half of

2004 of several pipeline systems that were acquired after or during the first half of 2003. See " Acquisitions." Revenues from all other pipeline systems increased approximately \$3.6 million to \$71.7 million. The increase is primarily related to increased volumes on our Basin pipeline system and a \$1.4 million favorable impact resulting from the decrease in the Canadian dollar to U.S. dollar exchange rate to an average of 1.34 to 1 for the first half of 2004, from an average of 1.45 to 1 for the first half of 2003.

Field operating costs increased to \$51.3 million in the first half of 2004 from \$27.7 million in the first half of 2003. This increase is predominately related to our continued growth, primarily from acquisitions, and is comprised primarily of higher payroll and utility costs.

Segment G&A expenses increased approximately \$8.9 million between comparable periods, primarily as a result of our Link acquisition along with a \$1.7 million accrual related to the vesting of unit grants under our LTIP. G&A costs have also increased because of increased headcount resulting from continued growth and higher costs related to requirements of the Sarbanes-Oxley Act of 2002. Additionally, the percentage of indirect costs allocated to the pipeline operations segment has increased in the 2004 period as our pipeline operations have grown. Including the impact of the items discussed above, segment profit was approximately \$73.2 million for the six months ended June 30, 2004, an increase of 65% as compared to the \$44.4 million reported for the six months ended June 30, 2003. Segment profit includes a \$0.8 million favorable impact resulting from the decrease in the average Canadian dollar to U.S. dollar exchange rate for the 2004 period as compared to the 2003 period.

The following table sets forth our operating results from our GMT&S Operations segment for the comparative periods indicated:

	Six Months Ended June 30,	
	2004	2003
Operating Results (in millions) ⁽¹⁾		
Revenues	\$ 8,572.6	\$ 5,689.3
Purchases and related costs	(8,464.2)	(5,591.9)
Field operating costs (excluding LTIP charge)	(45.7)	(38.0)
LTIP charge operations	(0.4)	
Segment G&A expenses (excluding LTIP charge) ⁽²⁾	(18.7)	(16.1)
LTIP charge general and administrative	(2.0)	
Segment profit	\$ 41.6	\$ 43.3
Noncash SFAS 133 impact ⁽³⁾	\$ 0.5	\$ 1.1
Maintenance capital	\$ 1.0	\$ 0.4
Average Daily Volumes (thousands of barrels per day) ⁽⁴⁾		
Crude oil lease gathering	550	430
Crude oil bulk purchases	135	78
Total	685	508
LPG sales ⁽⁵⁾	40	35

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

Table continued on following page.

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- (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) 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) Prior period volumes have been adjusted for consistency of comparison between years. Sales reflect only third party volumes.

Additionally, field operating costs and segment G&A expenses both increased during the period. Field operating costs increased to approximately \$46.1 million in the current period from \$38.0 million in the prior year period. This increase is primarily related to the Link acquisition. Also included is an approximately \$0.4 million LTIP charge in the 2004 period. Segment G&A expenses increased to \$20.7 million in the current period from \$16.1 million in the 2003 period. The increase is primarily related to the inclusion of the \$2.0 million LTIP charge in the 2004 period and increased headcount from continued growth and higher costs related to Sarbanes-Oxley requirements. This segment G&A increase is partially offset by lower costs being allocated to our GMT&S segment as our Pipeline Operations segment continues to grow.

The crude oil volumes gathered from producers, using our assets or third-party assets, has increased by 28% during the first half of 2004. The increase is related to the Link acquisition and organic growth and other acquisitions, which has offset natural production declines. In addition, we marketed 40,000 barrels per day of LPG during the first six months of 2004 compared to 35,000 barrels per day in the first six months of 2003. Segment profit per barrel calculated based on our lease gathered crude oil and LPG sales volumes was \$0.39 per barrel for the six months ended June 30, 2004, compared to \$0.52 for the six months ended June 30, 2003. The impact of change in the non-cash SFAS 133 mark-to-market for the first half of 2004 as compared to the first half of 2003 was a decrease in segment profit per barrel of approximately \$0.02. Additionally, segment profit per barrel was negatively impacted by lower segment profit per barrel on the lease gathered barrels added in the 2004 quarter from the Link acquisition. Per barrel profits related to the Link acquisition are lower because Link's gathering business primarily supported its pipeline operations.

Revenues from our gathering, marketing, terminalling and storage operations were approximately \$8.6 billion and \$5.7 billion for the six months ended June 30, 2004 and 2003, respectively. As discussed above, 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. The average NYMEX price for crude oil was \$36.78 per barrel and \$31.42 per barrel for the six months ended June 30, 2004 and 2003, respectively.

Other Expenses

Depreciation and Amortization. Depreciation and amortization expense was \$29.1 million for the six months ended June 30, 2004, compared to \$22.2 million for the six months ended June 30, 2003. The increase relates primarily to the assets from our 2004 acquisitions and our various 2003 acquisitions being included for the full six months in 2004 versus only a part or none of the six months in 2003. Additionally, several capital projects were completed during mid-to-late 2003 that were not included in the first six months of 2003 depreciation expense. Amortization of debt issue costs was \$1.2 million and \$2.0 million in the first half of 2004 and 2003, respectively.

Interest Expense. During the first half of 2004, our average debt balance was approximately \$771 million. This balance consisted of fixed rate senior notes with a face amount totaling \$450 million and borrowings under our revolving credit facilities averaging \$321 million. During the comparable 2003 period, our average debt balance was approximately \$520 million and consisted of fixed rate senior notes with a face amount of \$200 million and borrowings under our revolving credit facilities of

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\$320 million. The higher average debt balance in the 2004 period was primarily related to the portion of our acquisitions that were not refinanced with equity during the period. Our financial growth strategy is to fund our acquisitions using a balance of debt and equity.

The net result of the changes to our debt structure and our interest rate hedging instruments mentioned above was an increase in the average amount of fixed rate debt outstanding in the first half of 2004 to approximately 58% as compared to approximately 38% in the first half of 2003. The new senior unsecured credit facilities reduced the interest rate on our credit facilities by approximately 100 basis points compared to the senior secured facility. In addition, during these two periods the average three-month LIBOR rate declined to 1.2% in 2004 from 1.3% in 2003.

The net impact of the items discussed above was an increase in interest expense in the first half of 2004 of approximately \$1.8 million to a total of \$19.5 million. The higher average debt in the 2004 period resulted in additional interest expense of approximately \$6.2 million, while at the same time our commitment and other fees decreased by approximately \$1.4 million. Our weighted average interest rate, excluding commitment and other fees, was approximately 4.9% for the first half of 2004 compared to 6.1% for the first half of 2003. The lower weighted average rate decreased interest expense by approximately \$3.0 million in the first half of 2004 compared to the first half of 2003.

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Three Years Ended December 31, 2003

The following table reflects our results of operations and maintenance capital for each segment (note that each of the items in the following table excludes depreciation and amortization).

	Pipeline	GMT&S
	(in millions)	
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	(1.4)	(4.3)
Segment G&A expenses (excluding LTIP charge) ⁽²⁾	(18.3)	(31.6)
LTIP charge general and administrative	(9.6)	(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
Year Ended December 31, 2001 ⁽¹⁾		
Revenues	\$ 357.4	\$ 6,528.3
Purchases	(266.7)	(6,383.6)
Field operating costs	(19.4)	(73.7)
Segment G&A expenses ⁽²⁾	(12.4)	(28.5)
Segment profit	\$ 58.9	\$ 42.5
Noncash SFAS 133 impact ⁽³⁾	\$	\$ 0.2
Maintenance capital	\$ 0.5	\$ 2.9

(1)

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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.

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

	Year Ended December 31,		
	2003	2002	2001
Operating Results (in millions) ⁽¹⁾			
Revenues			
Tariff activities	\$ 153.3	\$ 103.7	\$ 69.4
Pipeline margin activities	505.3	382.5	288.0
Total pipeline operations revenues	658.6	486.2	357.4
Costs and Expenses			
Pipeline margin activities purchases	(487.1)	(362.2)	(266.7)
Field operating costs (excluding LTIP charge)	(60.9)	(40.1)	(19.4)
LTIP charge operations	(1.4)		
Segment G&A expenses (excluding LTIP charge) ⁽²⁾	(18.3)	(13.2)	(12.4)
LTIP charge general and administrative	(9.6)		
Segment profit	\$ 81.3	\$ 70.7	\$ 58.9
Maintenance capital	\$ 6.4	\$ 3.4	\$ 0.5
Average Daily Volumes (thousands of barrels per day) ⁽³⁾⁽⁴⁾			
Tariff activities			
All American	59	65	69
Basin	263	93	N/A
Other domestic	299	219	144
Canada	203	187	132
Total tariff activities	824	564	345
Pipeline margin activities	78	73	61
Total	902	637	406

(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.

(4) We have decreased the number of barrels previously disclosed in the "Other domestic" line for the 2002 period by approximately 9,000. The adjustment reflects an elimination of the duplication caused by reflecting volumes that were transported by truck in addition to being transported by pipeline. We believe this elimination more accurately reflects our business on this pipeline.

Total average daily volumes transported were approximately 902,000 barrels per day for the year ended December 31, 2003, compared to 637,000 barrels per day and 406,000 barrels per day for the years ended December 31, 2002 and 2001, respectively. As discussed above, we have completed a number of acquisitions during 2003 and 2002 that have impacted the results of operations.

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The following table reflects our total average daily volumes from our tariff activities by year of acquisition for comparison purposes:

	Year Ended December 31,		
	2003	2002	2001
	(thousands of barrels per day)		
Tariff activities⁽¹⁾			
2003 acquisitions	82		
2002 acquisitions	344	171	
2001 acquisitions	200	193	134
All other pipeline systems	198	200	211
	824	564	345
Total tariff activities	824	564	345

(1) 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 average daily volumes from our tariff activities to 824,000 barrels per day in 2003 from 564,000 barrels per day and 345,000 barrels per day in 2002 and 2001, respectively, resulted primarily from our acquisition activities discussed above. The following discussion explains year-to-year variances based on the comparison of volumes in the table above.

2003 Acquisitions Approximately 82,000 barrels per day of the increase in 2003 volumes over 2002 volumes is related to systems acquired during 2003.

2002 Acquisitions An additional 173,000 barrels per day of the increase in 2003 resulted from the inclusion of assets acquired in 2002 for the entire year in 2003 as compared to only a portion of 2002. The assets acquired in the Shell acquisition accounted for 171,000 barrels per day of this increase as increased barrels per day on the Basin Pipeline System and the Permian Basin Gathering System coupled with the impact of including a full year results in 2003 as compared to only five months in 2002 more than offset the decrease in barrels per day resulting from the shut-down of the Rancho Pipeline System. See "Business Acquisitions and Dispositions Shutdown and Sale of Rancho Pipeline System."

2001 Acquisitions In addition, volumes on pipeline systems acquired in 2001 increased by approximately 7,000 barrels per day in the 2003 period as Canadian volumes benefited from the completion of capital expansion projects that allowed for additional volumes on certain pipelines. Barrels per day on these systems increased in the 2002 period as compared to the 2001 period primarily due to the inclusion of the Murphy acquisition for a full year in 2002 compared to only a portion of the year in 2001.

All other pipeline systems Volumes on all other pipeline systems decreased approximately 2,000 barrels per day primarily because of a 6,000 barrel per day decrease in our All American tariff volumes and various other decreases totaling 4,000 barrels per day on several of our pipeline systems. The decrease in All American tariff volumes is attributable to a decline in California outer continental shelf ("OCS") production. Partially offsetting these decreases was an 8,000 barrel per day increase in our West Texas Gathering System volumes. Our West Texas Gathering System has benefited from the shutdown of the Rancho pipeline and also from temporary refinery problems that have diverted crude oil barrels from other systems. Volumes on all other pipeline systems decreased by approximately 11,000 barrels per day in 2002 as compared to 2001, primarily because of an approximate 4,000 barrel per day decrease in our All American tariff volumes and a 4,000 barrel per day decrease in our West Texas Gathering System volumes.

Revenues. Total revenues from our pipeline operations were approximately \$658.6 million for the year ended December 31, 2003, compared to \$486.2 million and \$357.4 million for the years ended December 31, 2002 and 2001, respectively. The increase in revenues was primarily related to our pipeline margin activities, which increased by approximately \$122.8 million in 2003. This increase was related to higher average crude oil prices coupled with increased volumes on our buy/sell arrangements on our San Joaquin Valley gathering system in 2003. 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. The increase in 2002 over 2001 also was primarily related to our pipeline margin activities on our San Joaquin Valley gathering system. Increased volumes and higher average prices on our buy/sell arrangements were the primary drivers of the increase.

Revenues from our tariff activities increased approximately 48% or \$49.6 million in 2003 as compared to 2002. The following table reflects revenues from our tariff activities by year of acquisition for comparison purposes:

	Year Ended December 31,		
	2003	2002	2001
	(in millions)		
Tariff activities⁽¹⁾			
2003 acquisitions	\$ 14.8	\$	\$
2002 acquisitions	54.2	23.1	
2001 acquisitions	28.0	21.6	9.9
All other pipeline systems	56.3	59.0	59.5
Total tariff activities	\$ 153.3	\$ 103.7	\$ 69.4

(1) Revenues include intersegment amounts.

The increase in revenues from our tariff activities to \$153.3 million in 2003 from \$103.7 million and \$69.4 million in 2002 and 2001, respectively, resulted predominantly from our acquisition activities discussed above. The following discussion explains year-to-year variances based on the comparison of revenues in the table above.

2003 Acquisitions Approximately \$14.8 million of the increase in 2003 revenues over 2002 revenues is related to systems acquired during 2003.

2002 Acquisitions An additional \$31.1 million of the increase in 2003 revenues from our tariff activities resulted from the inclusion of assets acquired in 2002 for the entire year in 2003 as compared to only a portion of 2002. This increase was entirely related to the assets acquired in the Shell acquisition as increased revenues on the Basin Pipeline System and the Permian Basin Gathering System coupled with the impact of including a full year results in 2003 as compared to only five months in 2002 more than offset the decrease in revenues resulting from the shut-down of the Rancho Pipeline System. See "Business Acquisitions and Dispositions Shutdown and Sale of Rancho Pipeline System."

2001 Acquisitions In addition, revenues from 2001 acquisitions increased approximately \$6.4 million in 2003 as compared to 2002. This increase predominately resulted from increased Canadian revenues of \$6.5 million in the 2003 period primarily due to expanded capacity, higher tariffs and a \$3.4 million favorable exchange rate impact. The favorable exchange rate impact has resulted from a decrease in the Canadian dollar to U.S. dollar exchange rate to an average rate of 1.40 to 1 for the year ended December 31, 2003, from an average rate of 1.57 to 1 for the year ended December 31, 2002. Revenues from these systems increased to \$21.6 million in 2002 from \$9.9 million in 2001

primarily because of the inclusion of the Murphy acquisition for a full year in 2002 and increases in the tariff of certain pipeline systems acquired in the Murphy acquisition.

All other pipeline systems Revenues from all other pipeline systems were relatively flat for all of the comparable periods as the decrease in volumes attributable to OCS production on our All American system (on which we receive the highest per barrel tariffs among our pipeline operations) was offset in each period by other increases, including increases in the tariffs for OCS volumes transported.

Field Operating Costs. Field operating costs increased to \$62.3 million in 2003 from \$40.1 million and \$19.4 million in 2002 and 2001, respectively. The 2003 increase in costs includes \$1.4 million related to the accrual made for the probable vesting of unit grants under our LTIP and approximately \$1.0 million related to a pipeline spill in Mississippi. The remaining increase is predominately related to our continued growth, primarily from acquisitions, coupled with higher utility costs.

The increase in field operating costs in 2002 as compared to 2001 was primarily related to the acquisition of businesses in 2002 and late 2001 and the inclusion of the results of the Murphy acquisition for all of 2002 compared to only a portion of 2001. Our field operating costs for the 2002 period also includes a \$1.2 million noncash charge associated with the establishment of a liability for potential cleanup of environmental conditions associated with our 1999 acquisitions, based on additional information. In many cases, the actual cash expenditure may not occur for ten years or more.

Segment G&A Expenses. Segment G&A expenses were approximately \$27.9 million in 2003, compared to approximately \$13.2 million and \$12.4 million in 2002 and 2001, respectively. The increase in 2003 is primarily a result of a \$9.6 million accrual related to the probable vesting of unit grants under our LTIP. Additionally, the percentage of indirect costs allocated to the pipeline operations segment has increased in 2003 as our pipeline operations have grown. The increase in segment G&A expenses in 2002 as compared to 2001 was partially due to increased costs from the assets acquired in the Murphy acquisition related to the inclusion of these assets for all of 2002 compared to only a portion of 2001.

Segment Profit. Our pipeline operations segment profit increased 15% to approximately \$81.3 million for the year ended December 31, 2003. Pipeline segment profit was approximately \$58.9 million in 2001. The primary reasons for the increase in segment profit are discussed above. In addition, segment profit includes a \$2.0 million favorable impact resulting from the decrease in the average Canadian dollar to U.S. dollar exchange rate for the 2003 period as compared to the 2002 period.

Maintenance Capital. For the periods ended December 31, 2003, 2002 and 2001, maintenance capital expenditures were approximately \$6.4 million, \$3.4 million and \$0.5 million, respectively for our pipeline operations segment. The increases between the years are related to our continued growth, primarily through acquisitions.

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The following table sets forth our operating results from our GMT&S segment for the periods indicated:

	December 31,		
	2003	2002	2001
Operating Results (in millions) ⁽¹⁾			
Revenues	\$ 11,985.6	\$ 7,921.8	\$ 6,528.3
Purchases and related costs	(11,799.8)	(7,765.1)	(6,383.6)
Field operating costs (excluding LTIP charge)	(73.3)	(66.3)	(73.7)
LTIP charge operations	(4.3)		
Segment G&A expenses (excluding LTIP charge) ⁽²⁾	(31.6)	(31.5)	(28.5)
LTIP charge general and administrative	(13.5)		
Segment profit	\$ 63.1	\$ 58.9	\$ 42.5
Noncash SFAS 133 impact ⁽³⁾	\$ 0.4	\$ 0.3	\$ 0.2
Maintenance capital	\$ 1.2	\$ 2.6	\$ 2.9
Average Daily Volumes (thousands of barrels per day) ⁽⁴⁾			
Crude oil lease gathering	437	410	348
Crude oil bulk purchases ⁽⁵⁾	90	68	46
Total	527	478	394
LPG sales	38	35	19

(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) 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) We have decreased the number of barrels previously disclosed in the "Crude oil bulk purchases" line for the 2002 period by approximately 12,000. The adjustment reflects an elimination of crude oil volumes improperly classified as bulk purchases.

The following factors contributed to our growth in segment profit during 2003 as compared to 2002:

the overall counter-cyclical balance of our assets and the flexibility embedded in our business strategy;

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increased tankage available to our gathering and marketing business;

increased lease gathering volumes;

the backwardated market structure and volatile market conditions;

increased sales and higher margins in our LPG activities for the first quarter because of cold weather throughout the U.S. and Canada; and

appreciation of Canadian currency (the Canadian dollar to U.S. dollar exchange rate appreciated to an average of 1.40 to 1 for the year ended December 31, 2003, from an average of 1.57 to 1 for the year ended December 31, 2002).

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As discussed above, 2002 market conditions were characterized by periods of weak contango and strong backwardation. Although these conditions are generally disadvantageous for our gathering and marketing activities, the 2001 market conditions were even less favorable. These market conditions and increased crude oil lease gathering volumes contributed to the growth in our segment profit in 2002 as compared to 2001. The increased volumes resulted predominantly from the inclusion of the assets acquired in the CANPET acquisition for the entire year in 2002 as compared to only a portion of 2001. The increase in segment profit was also impacted by decreased field operating costs in the 2002 period as compared to the 2001 period as discussed further below.

Field operating costs included in segment profit increased to approximately \$77.6 million in the year ended December 31, 2003 compared to \$66.3 million and \$73.7 million for the years ended December 31, 2002 and 2001, respectively. The increase in 2003 includes \$4.3 million related to the probable vesting of unit grants under our LTIP. The remaining increase was partially related to our continued growth, primarily from acquisitions, coupled with increased regulatory compliance activities and higher fuel costs. The decrease in field operating costs in 2002 as compared to 2001 was primarily related to the inclusion in 2001 of a \$5.0 million noncash writedown of operating crude oil inventory and a \$2.0 million noncash reserve for doubtful accounts.

Segment G&A expenses include the costs directly associated with the segments, as well as a portion of corporate overhead costs considered allocable. See " Other Income and Expenses." Segment G&A expense increased to \$45.1 million in 2003 compared to \$31.5 million and \$28.5 million for 2002 and 2001, respectively. Included in the 2003 amount is \$13.5 million related to the accrual for the probable vesting of unit grants under our LTIP. The percentage of indirect costs allocated to the Gathering, Marketing, Terminalling and Storage Operations segment has decreased from period to period as our pipeline operations have grown, partially offsetting the impact of the overall increase in G&A resulting from our continued growth. Segment G&A expenses increased in 2002 from 2001 primarily because of increased costs of \$5.6 million from the assets acquired in the CANPET acquisition due to the inclusion of those assets for all of 2002 compared to only a portion of 2001. This increase was offset by decreased segment G&A of \$2.6 million from our domestic operations. This decrease was partially related to a reduction in accounting and consulting costs in 2002 from those that had been incurred in 2001. Partially offsetting these items is the approximately \$2.4 million favorable impact on segment profit because of the appreciation of the Canadian dollar.

The crude oil volumes gathered from producers, using our assets or third-party assets, has increased by 7% and 18% during 2003 and 2002, respectively. The increase in 2003 is primarily related to organic growth and acquisitions, which has offset natural production declines. The increase in 2002 resulted primarily from our acquisition activities. In addition, we marketed 38,000 barrels per day of LPG during 2003 compared to 35,000 barrels per day and 19,000 barrels per day in 2002 and 2001, respectively. The increase in 2002 is primarily related to the inclusion of a full year of our LPG operations in the 2002 period compared to only six months during 2001. Segment profit per barrel calculated based on our lease gathered crude oil and LPG barrels was \$0.36 per barrel for the year ended December 31, 2003, compared to \$0.36 and \$0.32 for the years ended December 31, 2002 and 2001, respectively.

Revenues from our gathering, marketing, terminalling and storage operations were approximately \$12.0 billion, \$7.9 billion and \$6.5 billion for the years ended December 31, 2003, 2002 and 2001, respectively. As discussed above, revenues and costs related to purchases for 2003 were impacted by higher average prices and higher volumes in the 2003 period as compared to the 2002 period. The average NYMEX price for crude oil was \$31.08 per barrel and \$26.10 per barrel for 2003 and 2002, respectively. The increase in revenues and costs related to purchases in 2002 as compared to 2001 was predominantly related to higher sales volumes, as the average NYMEX price for crude oil in 2002 was only \$0.12 higher than the \$25.98 average in 2001.

Maintenance capital. For the periods ended December 31, 2003, 2002 and 2001, maintenance capital expenditures were approximately \$1.2 million, \$2.6 million and \$2.9 million, respectively for our gathering, marketing, terminalling and storage operations segment. The decrease in 2003 as compared to 2002 and 2001 is primarily because of a reduction in costs associated with information systems and the replacement of a portion of our fleet.

Other Income and Expenses

Unallocated G&A Expenses. Total G&A expenses were \$73.0 million, \$45.7 million and \$46.6 million for the years ended December 31, 2003, 2002 and 2001, 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.

During 2001, we incurred charges of \$5.7 million that were not attributable to a segment, related to incentive compensation paid to certain officers and key employees of Plains Resources and its affiliates. In 1998 (in connection with our IPO) and 2000, Plains Resources granted certain officers and key employees of the former general partner the right to earn ownership in a portion of our common units owned by it. These rights provided for vesting over a three-year period, subject to distributions being paid on the common and subordinated units. In connection with the general partner transition in 2001, these rights, as well as grants to directors under our LTIP, vested. This resulted in a charge to our 2001 income of approximately \$6.1 million, of which Plains Resources funded approximately 94%. Approximately \$5.7 million of the charge was noncash and was not allocated to a segment.

Depreciation and Amortization. Depreciation and amortization expense was \$46.8 million for the year ended December 31, 2003, compared to \$34.1 million and \$24.3 million for the years ended December 31, 2002 and 2001, respectively. The increase in 2003 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 \$3.8 million in 2003, and was essentially unchanged from \$3.7 million in 2002.

The increase in 2002 over 2001 consists of approximately \$4.1 million related to the inclusion of assets from the Shell acquisition and approximately \$3.5 million related to the inclusion of the assets from the Murphy and CANPET acquisitions for all of 2002 compared to only a portion of 2001. The remainder of the increase is related to increased debt issue costs related to the amendment of our credit facilities during 2002 and late 2001, the sale of senior notes in September 2002 and the completion of various capital projects.

Interest Expense. Interest expense was \$35.2 million for the year ended December 31, 2003, compared to \$29.1 million for each of the years ended December 31, 2002 and 2001, respectively. 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, long-term debt,

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 our 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%.

Interest expense was relatively flat in the 2002 period as compared to 2001 due to the impact of higher debt levels and commitment fees offset by lower average interest rates and the capitalization of interest. The overall increased average debt balance in 2002 is due to the portion of the Shell acquisition in August 2002 which was not financed with the issuance of equity. During the third quarter of 2001, we issued a \$200 million senior secured term B loan, the proceeds of which were used to reduce borrowings under our revolver. As such, our commitment fees on our revolver increased as they are based on unused availability. The lower interest rates in 2002 are due to a decrease in LIBOR and prime rates in the current year. In addition, approximately \$0.8 million of interest expense was capitalized during 2002, in conjunction with expansion construction on our Cushing terminal compared to approximately \$0.2 million in the 2001 period.

Other. 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. 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

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.

During the third quarter of 2004, we acquired the Schaefferstown Propane Storage Facility from Koch Hydrocarbon, L.P. The total purchase price was approximately \$32 million. In connection with the transaction, we also acquired an additional \$14.2 million of inventory. The facility is located approximately 65 miles northwest of Philadelphia near Schaefferstown, Pennsylvania, and has the capacity to store approximately 20.0 million gallons of refrigerated propane. In addition, the facility has nineteen bullet storage tanks with an aggregate capacity of 570,000 gallons. Propane is delivered to the facility via truck or pipeline and is transported out of the facility by truck. The transaction also included approximately 61 acres of land and a truck rack. The preliminary purchase price was allocated to property and equipment.

Link Energy LLC Acquisition. The completion and integration of the Link acquisition began impacting our operating results in the second quarter of 2004. We anticipate that the assets acquired in the acquisition will generate a baseline cash flow from operations of approximately \$25.0 million annually. In addition, we believe that we will realize annual cost savings and synergies of approximately \$27.0 million to \$32.0 million that are expected to be phased in by the first quarter of 2005 as the

business is fully integrated. However, we also anticipate certain one-time expense items in the initial six to nine month period as a result of integration costs, as well as costs associated with regulatory requirements. These costs will have a negative impact in the short-term on our baseline projection for the acquisition.

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. Such drilling activities, if successful, are not expected to have a significant impact on pipeline shipments on our All American Pipeline system in 2004 but, could lead to increased volumes in future periods. However, we can give no assurances that our volumes transported would increase as a result of this drilling activity.

Distribution Increase. Management intends to recommend to the board of directors an increase in our quarterly distribution for the third quarter of 2004 to \$0.60 per unit, or \$2.40 per unit on an annualized basis. If approved by the board, the distribution increase would be effective with the distribution to be paid in mid-November 2004. An annualized distribution rate of \$2.40 per unit would represent an increase of approximately 4% over its current annualized distribution of \$2.31 per unit and a 9% increase over the November 2003 distribution. You should be aware that management's recommendation is subject to the approval of its board of directors, which holds the sole authority to declare quarterly distributions to unitholders.

Sarbanes-Oxley Act and New SEC Rules. 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 repetition of those events. Implementation of reforms in connection with these initiatives have added and will add to the costs of doing business for all publicly-traded entities, including us as a partnership. These costs will have an adverse impact on future income and cash flow.

Among the new requirements is the requirement under Section 404 of the Act, beginning with our 2004 Annual Report, for management to report on our internal control over financial reporting and for our independent public accountants to attest to management's report. During 2003, we commenced actions to enhance our ability to comply with these requirements, including but not limited to the addition of staffing in our internal audit department, documentation of existing controls and implementation of new controls or modification of existing controls as deemed appropriate. We have continued to devote substantial time and resources to the documentation and testing of our controls, and to planning for and implementation of remedial efforts in those instances where remediation is indicated. At this point, we have no indication that management will be unable to favorably report on our internal controls nor that our independent auditors will be unable to attest to management's findings. Both we and our auditors, however, must complete the process (which we have never completed before), so we cannot assure you of the results. It is unclear what impact failure to comply fully with Section 404 or the discovery of a material weakness in our internal control over financial reporting would have on us, but presumably it could result in the reduced ability to obtain financing, the loss of customers, and additional expenditures to meet the requirements.

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 lines.

3. Aggressive practices in the U.S. to maintain working crude oil inventory levels below historical levels.
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 introduction of increased crude oil production from North American supplies (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 June 30, 2004, we had a working capital deficit of approximately \$26.2 million, approximately \$342.6 million of availability under our committed revolving credit facilities and \$168.0 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.

As discussed above, we closed the Link acquisition on April 1, 2004. The acquisition was funded with cash on hand, borrowings under a new \$200 million, 364-day credit facility and borrowings under our existing revolving credit facilities. The new credit facility was terminated following our August 2004 debt offering described below. In connection with the Link acquisition, on April 15, 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, were approximately \$101 million, and were used to reduce the balance outstanding under our existing revolving credit facilities.

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 \$7.4 million. Net proceeds of \$161.1 million were used to permanently reduce outstanding borrowings under the new \$200 million, 364-day credit facility discussed above.

On August 12, 2004, we sold \$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% 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 \$345.3 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.

We have recently increased the capacity of our uncommitted senior secured hedged inventory facility from \$200 million to \$300 million, primarily as a result of increased crude oil prices and an increase in our crude oil storage capacity as a result of acquisitions.

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.

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 spend approximately \$125 million to \$150 million on expansion capital projects during 2004. In addition, we expect to spend approximately \$14.1 million on maintenance capital projects during 2004. For the first half of 2004, we have incurred approximately \$32.0 million related to expansion capital projects and approximately \$3.1 million on maintenance capital projects.

We will also have additional cash funding requirements related to the Link acquisition. The aggregate estimated purchase price for the Link acquisition is approximately \$326.1 million, of which approximately \$268.5 million (net of approximately \$5.5 million subsequently returned to us from an indemnity escrow account) was funded at closing. The approximately \$58.0 million balance includes acquisition related costs and net liabilities assumed.

Cash Flows

Cash flows for the six months ended June 30, 2004 and 2003 were as follows:

	Six Months Ended June 30,	
	2004	2003
	(in millions)	
Cash provided by (used in):		
Operating activities	\$ 147.1	\$ 204.8
Investing activities	(474.6)	(139.8)
Financing activities	334.0	(63.0)

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, general and administrative expenses and interest expense. 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. 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 crude oil, we borrow on our credit facilities to pay for the crude oil and 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. To a lesser extent, our cash flow from operating activities is also impacted by the level of LPG inventory stored at period end. Cash flow from operations was \$147.1 million and \$204.8 million for the six months ended June 30, 2004 and 2003, respectively.

Investing Activities. Net cash used in investing activities for the six months ended June 30, 2004 and 2003 consisted predominantly of cash paid for acquisitions. Net cash used in the 2004 period was \$474.6 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), (ii) approximately \$280 million paid for the Link acquisition, (iii) approximately \$19 million paid for the CalVen acquisition and (iv) \$32.2 million paid for additions to property and equipment. Included in cash paid for additions to property and equipment is (i) approximately \$6.6 million related to the Cushing Phase IV expansion, (ii) approximately \$5.0 million related to the Iatan System expansion, (iii) approximately \$3.0 million of maintenance capital, and (iv) approximately \$1.2 million related to the Cushing to Caney pipeline project. Net cash used in investing activities in the 2003 period includes approximately \$79.6 million paid for acquisitions and approximately \$37.5 million for additions to property and equipment. In addition, approximately \$28.5 million was paid for linefill on assets that we own.

Financing Activities. Cash provided by financing activities in the 2004 period was approximately \$334.0 million and was comprised of (i) approximately \$100.9 million of proceeds from the issuance of Class C common units, (ii) net short and long-term borrowings under our revolving credit facility of approximately \$403.7 million used primarily to fund the purchase price of the Capline and Link acquisitions, (iii) net repayments under our short-term letter of credit and hedged inventory facility of approximately \$96.1 million resulting from the collection of receivables related to prior year sales of inventory that was stored because of contango market conditions, and (iv) \$72.7 million of distributions paid to common unitholders and the general partner. Cash used in financing activities in the 2003 period consisted of (i) approximately \$63.9 million of proceeds from the issuance of common units used to pay down outstanding balances on the revolving credit facility, (ii) \$58.8 million of distributions paid to unitholders and the general partner, (iii) a \$7.0 million repayment of a maturity under our senior secured term loan, (iv) net long-term borrowings under our revolving credit facilities of \$29.1 million, and (v) net short-term debt repayments of \$90.2 million primarily from the proceeds of inventory sales.

Cash flows for the years ended December 31, 2003, 2002 and 2001 were as follows:

	Year ended December 31,		
	2003	2002	2001
	(in millions)		
Cash provided by (used in):			
Operating activities	\$ 115.3	\$ 185.0	\$ (16.2)
Investing activities	(272.1)	(374.9)	(263.2)
Financing activities	157.2	189.5	279.5

Operating Activities. 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.

Our negative cash flow from operations for 2001 resulted from positive cash generated by our recurring operations offset by the payment of approximately \$93 million for crude oil hedged and stored during 2001 for which receipt of the proceeds occurred during 2002.

Investing Activities. Net cash used in investing activities in 2003, 2002 and 2001 consisted predominantly of cash paid for acquisitions and purchases of linefill. Net cash used in 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 acquisition from Shell Pipeline Company; 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. Net cash used in 2001 was \$263.2 million and was comprised of (i) an aggregate \$229.2 million paid for three acquisitions completed during 2001; see " Acquisitions", and (ii) \$21.1 million paid for additions to property and equipment, and (iii) approximately \$13.7 million of crude oil linefill attributable to increased linefill requirements.

Financing Activities. 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.

Cash provided by financing activities in 2001 consisted primarily of net short-term and long-term borrowings of \$134.3 million, proceeds from the issuance of common units of \$227.5 million, and the payment of \$75.9 million in distributions to our unitholders and general partner.

Contingencies

Industry Credit Markets and Accounts Receivable. Throughout the latter part of 2001 and all of 2002, there were significant disruptions and extreme volatility in the financial markets and credit markets. Because of the credit intensive nature of the energy industry and extreme financial distress at several large, diversified energy companies, the energy industry was especially impacted by these

developments. We believe that these developments have created an increased level of direct and indirect counterparty credit and performance risk.

The majority of our credit extensions relate to our gathering and marketing activities that can generally be described as high volume and low margin activities. During periods of relatively higher prices, our absolute exposure to any given counterparty may be increased. In our credit approval process, 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. As of June 30, 2004, we had received approximately \$18.3 million of advance cash payments and prepayments from third parties to mitigate credit risk.

Pipeline and Storage Regulation. Some 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. Comparable regulation exists in Canada and in some states in which we conduct intrastate common carrier or private pipeline operations. See "Business Regulation Pipeline and Storage Regulation."

Regulatory compliance costs include those related to pipeline integrity management and the adoption by the DOT of API 653 as the standard for the inspection, repair, alteration and reconstruction of jurisdictional storage tanks. For our estimates of costs associated with these regulations, see "Business Regulation Pipeline and Storage 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.

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. Department of Commerce. In 2002, we determined that we may have exceeded the quantity of crude oil exports authorized by previous licenses. Export of crude oil in excess of the authorized amounts is a violation of the EAR. On October 18, 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 a new license allowing for exports of volumes more than adequately reflecting our anticipated 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 are cooperating with the BIS in its inquiry. At this time, we have received no indication whether the BIS intends to charge us with a violation of the EAR or, if so, what penalties would be assessed. As a result, we cannot 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, asserts 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 seeks 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, subject to the preparation and execution of appropriate settlement documentation and court approval.

Litigation. 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.

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 trend 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.

The occurrence of a significant event not fully insured or indemnified against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe that 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.

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.

Credit Facilities and Long-Term Debt

During August 2004, we completed the sale of \$175 million of 4.750% senior notes due August 2009 and \$175 million of 5.875% senior notes due August 2016. The notes were issued by us and a 100% owned finance subsidiary (neither of which have independent assets or operations) at an aggregate discount of \$2.2 million, resulting in an effective average interest rate of 5.40%. Interest payments on each series of notes are due February 15 and August 15 of each year. The notes are fully and unconditionally guaranteed, jointly and severally, by all of our existing 100% owned subsidiaries, except for subsidiaries that are minor.

During December 2003, we completed the sale of \$250 million of 5.625% senior notes due December 2013. The notes were issued by us and a 100% owned finance subsidiary (neither of which have independent assets or operations) 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. The notes are fully and unconditionally guaranteed, jointly and severally, by all of our existing 100% owned subsidiaries, except for subsidiaries that are minor.

We have senior unsecured bank credit facilities consisting of:

\$425 million U.S. revolving credit facility terminating in 2007;

\$170 million Canadian revolving credit facility terminating in November 2004 with a five-year term-out option; and

\$30 million Canadian working capital revolving credit facility terminating in 2007.

We also have a secured \$300 million hedged inventory facility (recently increased from \$200 million). This facility is an uncommitted working capital facility, which will be used to finance the purchase of hedged crude oil inventory for storage when market conditions warrant. Borrowings under the hedged inventory facility will be 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. At June 30, 2004, we had approximately \$4.4 million outstanding and \$27.6 million of letters of credit issued under our hedged crude oil inventory facility resulting in unused uncommitted capacity of approximately \$268.0 million under this facility (pro forma for the recent increase to \$300 million).

Our credit facilities, the indentures governing the 4.750% senior notes, 5.625% senior notes, 5.875% senior notes and 7.75% senior notes contain cross default provisions. Our credit facilities 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 facilities treat a change of control as an event of default and also require 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 4.5 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 facilities would permit the lenders to accelerate the maturity of the outstanding debt. As long as we are in compliance with our credit agreements, they do not restrict our ability to make distributions of available cash as defined in "Cash Distribution Policy Distributions of Available Cash." We are currently in compliance with the covenants contained in our credit facilities and indentures.

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The average life of our long-term debt capitalization at June 30, 2004, was approximately 6 years. At June 30, 2004 we had approximately \$13.2 million of short-term working capital borrowings and \$90.0 million of long-term borrowings outstanding under our \$425 million U.S. revolving credit facility, no amounts outstanding under our \$125 million, 364-day revolving credit facility, \$25.7 million outstanding under our \$30 million Canadian working capital revolving credit facility, \$170.0 million outstanding under our \$170 million Canadian revolving credit facility that matures in 2009,

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\$200.0 million outstanding under our new \$200 million, 364-day revolving credit facility, \$200 million of senior notes that mature in 2012 and \$250 million of senior notes that mature in 2013.

Commitments

Contractual Obligations. In the ordinary course of doing business we enter into various contractual obligations for varying terms and amounts. The following table includes our non-cancelable contractual obligations as of June 30, 2004, and our best estimate of the period in which the obligation will be settled:

	2004	2005	2006	2007	2008	Thereafter	Total
	(in millions)						
Long-term debt	\$	\$ 200.0	\$	\$ 115.8	\$	\$ 620.0	\$ 935.8
Operating leases ⁽¹⁾	9.3	15.8	13.8	10.2	3.8	12.4	65.3
Capital expenditure obligations	76.4						76.4
Other long-term liabilities	1.5	0.5	0.2				2.2
Total	\$ 87.2	\$ 216.3	\$ 14.0	\$ 126.0	\$ 3.8	\$ 632.4	\$ 1,079.7

(1) Operating leases are primarily for office rent and trucks used in our gathering activities.

In addition to the items in the table above, we have entered into various operational commitments and agreements related to pipeline operations and to the marketing, transportation, terminalling and storage of crude oil and the marketing and storage of LPG. The majority of these contractual commitments are for the purchase of crude oil and LPG that are made under contracts that range in term from a thirty-day evergreen to three years. A substantial portion of the contracts that extend beyond thirty days include cancellation provisions that allow us to cancel the contract with thirty days written notice. From time to time, we also 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. Through these transactions, we seek to maintain a position that is substantially balanced between crude oil and LPG purchases and sales and future delivery obligations. The volume and prices of these purchase and sale contracts are subject to market volatility and fluctuate with changes in the NYMEX price of crude oil from period to period. During the second quarter 2004, these purchases averaged approximately \$1.6 billion per month.

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 June 30, 2004, we had outstanding letters of credit under our various facilities of approximately \$136.1 million.

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 cash and cash equivalents on hand at the end of the quarter less reserves established by our general partner for future requirements. On August 13, 2004, we paid a cash distribution of \$0.5775 per unit on all outstanding units. The total distribution paid was approximately \$41.8 million, with approximately \$38.8 million paid to our common unitholders and approximately \$3.0 million paid to our general partner for its general partner (\$0.8 million) and incentive distribution interests (\$2.2 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 2003, we paid \$4.4 million in incentive distributions to our general partner. Thus far in 2004 (through August 13, 2004), we have paid \$5.6 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 307 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 price 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, sales and transportation 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 (see Note 5 to our consolidated financial statements for a discussion of the mitigation of credit risk beginning on page F-45 of this prospectus). 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 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 partial 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 than in the past. This accounting treatment is discussed further under Note 2 "Summary of Significant Accounting Policies" beginning on page F-35 of this prospectus.

All of our open commodity price risk derivatives at June 30, 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	\$ 18.6	\$ (1.4)
Swaps and options contracts	\$ (4.6)	\$ 2.5
LPG:		
Futures contracts	\$	\$
Swaps and options contracts	\$ (1.0)	\$ 1.3

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. 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, 2003. The 7.75% senior notes issued during 2002 and the 5.625% senior notes issued during 2003 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

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in effect at June 30, 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.

Expected Year of Maturity

	2004	2005	2006	2007	2008	Thereafter	Total
	(in millions)						
Liabilities:							
Short-term debt variable rate	\$ 22.0	\$	\$	\$	\$	\$	\$ 22.0
Average interest rate	3.3%						3.3%
Long-term debt variable rate	\$	\$ 200.0	\$	\$ 115.8	\$	\$ 170.0	\$ 485.8
Average interest rate		2.3%		2.8%		2.3%	2.4%

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, forward extra option contracts and cross currency swaps. Additionally, at times, a portion of our debt is denominated in Canadian dollars. At December 31, 2003, we did not have any Canadian dollar debt. All of the financial instruments utilized are placed with large creditworthy financial institutions.

At June 30, 2004, we had forward exchange contracts that allow us to exchange \$2.0 million Canadian for at least \$1.5 million U.S. quarterly during 2004 (based on a Canadian dollar to U.S. dollar exchange rate of 1.33 to 1) and \$1.0 million Canadian for at least \$0.7 million U.S. quarterly during 2005 (based on a Canadian dollar to U.S. dollar exchange rate of 1.34 to 1). At June 30, 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 reduces by \$2.0 million U.S. in May 2005 and has a final maturity in May 2006 (\$19.0 million U.S.).

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				
	2004	2005	2006	2007	Total
Forward exchange contracts	\$ 0.1	\$	\$	\$	\$ 0.1
Cross currency swaps	(0.2)	(0.6)	(2.8)		(3.6)
Total	\$ (0.1)	\$ (0.6)	\$ (2.8)	\$	\$ (3.5)

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 other petroleum products. We refer to liquefied petroleum gas and other 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 June 30, 2004, we owned approximately 15,000 miles of gathering and mainline crude oil pipelines located throughout the United States and Canada. 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 June 30, 2004, we owned approximately 37 million barrels of above-ground crude oil terminalling and storage facilities, including tankage associated with our pipeline systems. 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 51 million gallons of LPG storage (72 million gallons giving effect to our August 2004 Schaefferstown acquisition). Our 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;

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 liquified petroleum gas and other petroleum products from producers, refiners and other marketers, 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 and expanding 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;

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 the Gulf Coast and Gulf of Mexico to take advantage of anticipated increases in the volume and qualities of crude oil produced in these areas; 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. Since that time, the portion of our Gathering, Marketing, Terminalling and Storage Operations segment profit associated with those activities has increased from \$4.2 million in 2001 to \$10.0 million in 2002 and \$11.6 million in 2003. The segment profit for 2001 reflects results from July 1 through December 31.

Financial Strategy

Targeted Credit Profile

We believe that a major factor in our continued success will be our ability to maintain a competitive cost of capital and access to the capital markets. Since our initial public offering in 1998, 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 second quarter 2004 results, and pro forma for our third quarter 2004 equity and debt offerings, we were within our targeted credit profile. 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 temporarily outside the parameters of our targeted credit profile.

Rating Agencies Update

In July 2004, Standard & Poor's removed us from creditwatch with negative implications and affirmed their BBB- stable senior unsecured rating (an investment grade rating). In August 2004, Moody's Investors Service upgraded our senior unsecured rating from Ba1 to Baa3 (an investment grade rating). 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. You should 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. These assets are strategically positioned to maximize the value of our 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, operationally flexible and readily expandable. 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 the most modern large-scale terminalling and storage facility at the Cushing Interchange, incorporating operational enhancements designed to safely and efficiently terminal, store, blend and segregate large volumes and multiple varieties of crude oil as well as extensive environmental safeguards. Our Phase IV expansion project, which became operational in July 2004, increased the total capacity of our Cushing Terminal by approximately 20% to approximately 6.3 million barrels. We believe that the facility can be further expanded to meet additional demand should market conditions warrant. 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 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 all 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 that 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 June 30, 2004, after giving effect to our July 2004 offering, our August 2004 debt offering and the termination of our \$125 million, 364-day credit facility, we would have had approximately \$516.5 million available under our committed revolving credit facilities. Our usage is 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 through phantom unit grants and options, own significant contingent equity incentives that vest only if we achieve specified performance objectives. A significant portion of the restricted unit grants under our Long Term Incentive Plan ("LTIP") have vested in 2004. In addition, our senior management team collectively owns approximately 650,000 common units.

Recent Developments

Board of Directors

On July 23, 2004, in connection with the acquisition of Plains Resources Inc. by Vulcan Energy Corporation, Plains All American GP LLC (the general partner of our general partner Plains AAP, L.P.), amended its limited liability company agreement to expand its board of directors from seven members to eight. As amended, the limited liability company agreement provides that the mechanism for determining the constituency of the board remains the same except that three independent directors, rather than two, are elected by majority vote of the owners of Plains All American GP LLC. Mr. J. Taft Symonds, the previous designee of Plains Holdings Inc., was elected as an independent director by majority vote of the members of Plains All American GP LLC to fill the vacancy created by the expansion of the board.

On July 26, 2004, Plains Holdings Inc. (a wholly owned subsidiary of Plains Resources Inc.) designated Mr. David N. Capobianco as one of our directors. Mr. Capobianco is a member of the board of Vulcan Energy Corporation and a managing director of Vulcan Capital, an affiliate of Vulcan Inc.

Distribution Increase

On August 13, 2004, we paid a cash distribution of \$0.5775 per unit on all outstanding limited partner units. This distribution equals an annual distribution of \$2.31 per unit and represents an increase of 5.0% over the second quarter of 2003 distribution. Management intends to recommend to the board of directors an increase in our quarterly distribution to \$0.60 per unit, or \$2.40 per unit on an annualized basis. If approved by the board, the distribution increase would be effective with the distribution to be paid in mid-November 2004. An annualized distribution rate of \$2.40 per unit would represent an increase of approximately 4% over its current annualized distribution of \$2.31 per unit and a 9% increase over the November 2003 distribution. You should be aware that management's recommendation is subject to the approval of its board of directors, which holds the sole authority to declare quarterly distributions to unitholders.

Schaefferstown Propane Storage Facility

In August 2004, we acquired the Schaefferstown Propane Storage Facility from Koch Hydrocarbon, L.P. The total purchase price was approximately \$32 million. In connection with the transaction, we also acquired an additional \$14.2 million of inventory. The facility is located approximately 65 miles northwest of Philadelphia near Schaefferstown, Pennsylvania, and has the capacity to store approximately 20.0 million gallons of refrigerated propane. In addition, the facility has nineteen bullet storage tanks with an aggregate capacity of 570,000 gallons. Propane is delivered to the facility via truck or pipeline and is transported out of the facility by truck. The transaction also included approximately 61 acres of land and a truck rack. The preliminary purchase price was allocated to property and equipment.

Common Unit Offering

During the third quarter of 2004, we completed a public offering of 4,968,000 common units. The net proceeds from the offering, including our general partner's proportionate capital contribution and expenses associated with the offering, were approximately \$161.1 million. We used the net proceeds to pay down outstanding indebtedness and reduce the commitment level under our \$200 million, 364-day credit facility.

LTIP Vesting

From January 1, 2004 through September 30, 2004, we have issued approximately 363,000 common units in satisfaction of the vesting of phantom units under our Long-Term Incentive Plan.

Debt Issuance

During August 2004, we completed the sale of \$175 million of 4.750% senior notes due August 2009 and \$175 million of 5.875% senior notes due August 2016 in a private placement pursuant to Rule 144A of the Securities Act of 1933. The net proceeds from the offering, after deducting the initial purchasers' discounts and our estimated offering expenses, were approximately \$345.3 million. We used the net proceeds to repay the remaining balance of approximately \$40.8 million outstanding under our \$200 million, 364-day credit facility. Following this payment, this facility was terminated and we used the remaining net proceeds to repay amounts outstanding under our revolving credit facilities and for general partnership purposes. As a result of this transaction, we recognized a noncash charge of approximately \$0.7 million associated with the write-off of unamortized debt issue costs.

Other Acquisition Activities

Since 1998, including our recent Schaefferstown acquisition, we have completed numerous acquisitions for an aggregate purchase price of approximately \$1.9 billion. 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 complimentary 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.

Organizational History

We were formed in September 1998 to acquire and operate the midstream crude oil business and assets of Plains Resources Inc. and its wholly-owned subsidiaries as a separate, publicly traded master limited partnership. We completed our initial public offering in November 1998. Unless the context otherwise requires, we refer to Plains Resources Inc. and its wholly owned subsidiaries as Plains Resources. As a result of subsequent equity offerings and the purchase in 2001 by senior management and a group of financial investors of majority control of our general partner and a portion of the limited partner units held by Plains Resources, Plains Resources' overall effective ownership in us was reduced to approximately 18.9% as of September 30, 2004. See "Security Ownership of Certain Beneficial Owners and Management and Related Unitholders' Matters."

As a result of the 2001 transaction, 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. 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 the largest interest, 44%, held by Plains Resources. We use the phrase "former general partner" to refer to the subsidiary of Plains Resources that formerly held the 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 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. References to our general partner, unless the context otherwise requires, include Plains All American GP LLC. Our general partner does not receive any 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 and Dispositions

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, 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.

Following is a brief description of selected acquisitions completed during the first half of 2004 and in 2003 and major acquisitions and dispositions that have occurred since our initial public offering in November 1998.

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 \$326 million, including \$268 million of cash (net of approximately \$5.5 million subsequently returned to PAA from an indemnity escrow account) and approximately \$58 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 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 gathering, marketing, terminalling and storage operations segments since April 1, 2004.

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. 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. Representatives from the Antitrust and Civil Medicaid Fraud Division of the Office of the Texas AG indicated their investigation was prompted by complaints received from allegedly interested industry parties regarding the potential impact on competition in the Permian Basin area of West Texas. We understand that similar complaints have been received by the Federal Trade Commission, and that, consistent with federal-state protocols for conducting joint merger investigations, appropriate federal and state antitrust authorities are coordinating their activities. In connection with the April notice and again in June 2004, the Texas AG requested information from us. We have complied with these requests and are cooperating fully with the antitrust enforcement authorities.

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

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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.

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 Pipe Line 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, including refineries owned by ConocoPhillips, ExxonMobil, BP, MarathonAshland, CITGO and Premcor. 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 sweet and light sour foreign crude to PADD II. With a total system operating capacity of 1.14 million barrels per day, approximately 248,000 barrels per day are subject to the interest acquired. During 2003, throughput on the interest we acquired averaged approximately 125,000 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. The Capwood System has the ability to deliver crude at Wood River to several other PADD II refineries and pipelines, including those owned by Koch and ConocoPhillips. 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.

South Saskatchewan Pipeline System

In November 2003, we completed the acquisition of the South Saskatchewan Pipeline System from South Saskatchewan Pipe Line Company. The South Saskatchewan Pipeline System originates approximately 75 miles southwest of Swift Current, Saskatchewan, and traverses north and east until it reaches its terminus at Regina, Saskatchewan. The system consists of a 158-mile, 16-inch mainline and 203 miles of gathering lines ranging in diameter from three to twelve inches. In 2002, the system transported approximately 52,000 barrels of crude oil per day. During the period of 2003 that we owned the system, it transported approximately 52,000 barrels of crude oil per day. For the six months ended June 30, 2004, the system transported approximately 47,000 barrels of crude oil per day. At Regina, the system can deliver crude oil to the Enbridge Pipeline System, as well as to local markets, and through the Enbridge connection crude can be delivered into our Wascana Pipeline System. Total purchase price for these assets was approximately \$48 million, including transaction costs.

ArkLaTex Pipeline System

In October 2003, we completed the acquisition of the ArkLaTex Pipeline System from Link Energy (formerly EOTT Energy). The ArkLaTex Pipeline System consists of 240 miles of active crude oil gathering and mainline pipelines and connects to our Red River Pipeline System near Sabine, Texas. Also included in the transaction were 470,000 barrels of active crude oil storage capacity, the

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assignment of certain of Link Energy's crude oil supply contracts and crude oil linefill and working inventory comprising approximately 108,000 barrels. The total purchase price for these assets of approximately \$21.3 million included approximately \$14.0 million of cash paid to Link Energy for the pipeline system, approximately \$2.9 million of cash paid to Link Energy to purchase crude oil linefill and working inventory, approximately \$3.6 million for estimated near-term capital costs and transaction costs and approximately \$0.8 million associated with the satisfaction of outstanding claims for accounts receivable and inventory balances.

Iraan to Midland Pipeline System

In June 2003, we acquired the Iraan to Midland Pipeline System from a unit of Marathon Ashland Petroleum LLC ("MAP") for aggregate consideration of approximately \$17.6 million. The Iraan to Midland Pipeline System is a 16-inch, 98-mile mainline crude oil pipeline that originates in Iraan, Texas and terminates in Midland, Texas. At Midland, the system has the ability to deliver crude oil to our Basin Pipeline System and to the Mesa Pipeline System. The Iraan to Midland Pipeline System transported approximately 22,000 barrels per day of crude oil in the first six months of 2004. The results of operations and assets of the Iraan to Midland Pipeline System have been included in our consolidated financial statements and our pipeline operations since June 30, 2003. The aggregate purchase price included \$13.6 million in cash, approximately \$3.6 million associated with the satisfaction of outstanding claims for accounts receivable and inventory balances, and approximately \$0.4 million of estimated transaction costs.

South Louisiana Assets

In June 2003, we completed the acquisition of terminalling and gathering assets from El Paso Corporation for approximately \$13.4 million, including transaction costs. These assets are located in southern Louisiana and include various interests in five pipelines and gathering systems and two terminal facilities. These assets complement our existing activities in south Louisiana and we believe will help leverage our exposure to the growing volume of crude oil and condensate production from the Gulf of Mexico. The results of operations and assets from this acquisition have been included in our consolidated financial statements and in our pipeline operations segment since June 1, 2003. The assets acquired in this acquisition include a 33¹/₃% interest in Atchafalaya Pipeline, L.L.C. In December 2003, we acquired the remaining 66²/₃% interests in two separate transactions totaling \$4.4 million.

Iatan Gathering System

In March 2003, we completed the acquisition of a West Texas crude oil gathering system from Navajo Refining Company, L.P. for approximately \$24.3 million, including transaction costs. The assets are located in the Permian Basin in West Texas and consist of approximately 360 miles of active crude oil gathering lines. The results of operations and assets from this acquisition have been included in our consolidated financial statements and in our pipeline operations segment since March 1, 2003.

Red River Pipeline System

In February 2003, we completed the acquisition of a 334-mile crude oil pipeline from BP Pipelines (North America) Inc. for approximately \$19.4 million, including transaction costs. The system originates at Sabine in East Texas and terminates near Cushing, Oklahoma. Subsequent to the acquisition, we connected the pipeline system to our Cushing Terminal. The system also includes approximately 645,000 barrels of crude oil storage capacity. The results of operations and assets from this acquisition have been included in our consolidated financial statements and in our pipeline operations segment since February 1, 2003. This pipeline complements our existing assets in East Texas.

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"). The primary assets included in the transaction are interests in the Basin Pipeline System ("Basin System"), the Permian Basin Gathering System ("Permian Basin System") and the Rancho Pipeline System ("Rancho System"). 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 acquired assets are primarily fee-based mainline crude oil pipeline transportation assets that gather crude oil in the Permian Basin and transport that crude oil to major market locations in the Mid-Continent and Gulf Coast regions. 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. In addition, we believe that the Basin system is poised to benefit from potential shut-downs of refineries and other pipelines due to the shifting market dynamics in the West Texas area. As was contemplated at the time of the acquisition, the Rancho system was taken out of service in March 2003, pursuant to the terms of its operating agreement. See "Shutdown and Partial Sale of Rancho Pipeline System."

Canadian Expansion

In early 2000, we articulated to the financial community our intent to establish a strong Canadian operation that complements our operations in the United States. In 2001, after evaluating the marketplace and analyzing potential opportunities, we consummated the two transactions detailed below in 2001. The combination of these assets, an established fee-based pipeline transportation business and a rapidly-growing, entrepreneurial gathering and marketing business, allowed us to optimize both businesses and establish what we believe to be a solid foundation for future growth in Canada.

CANPET Energy Group, Inc. In July 2001, we purchased substantially all of the assets of CANPET Energy Group Inc., a Calgary-based Canadian crude oil and LPG marketing company, for approximately \$24.6 million plus \$25.0 million for additional inventory owned by CANPET. In December 2003 we recorded an additional \$24.3 million related to a portion of the purchase price that had previously been deferred subject to various performance standards of the business acquired. See Note 7 "Partners' Capital and Distributions" in the "Notes to the Consolidated Financial Statements." The principal assets acquired included a crude oil handling facility, a 130,000-barrel tank facility, LPG facilities, existing business relationships and operating inventory.

Murphy Oil Company Ltd. Midstream Operations. In May 2001, we completed the acquisition of substantially all of the Canadian crude oil pipeline, gathering, storage and terminalling assets of Murphy Oil Company Ltd. for approximately \$161.0 million in cash, including financing and transaction costs. The purchase price included \$6.5 million for excess inventory in the systems. The principal assets acquired include (i) approximately 560 miles of crude oil and condensate mainlines (including dual lines on which condensate is shipped for blending purposes and blended crude is shipped in the opposite direction) and associated gathering and lateral lines, (ii) approximately 1.1 million barrels of crude oil storage and terminalling capacity located primarily in Kerrobert, Saskatchewan, (iii) approximately 254,000 barrels of pipeline linefill and tank inventories, and (iv) 121 trailers used primarily for crude oil transportation.

West Texas Gathering System

In July 1999, we completed the acquisition of the West Texas Gathering System from Chevron Pipe Line Company for approximately \$36.0 million, including transaction costs. The assets acquired include approximately 420 miles of crude oil mainlines, approximately 295 miles of associated gathering and lateral lines, and approximately 2.7 million barrels of tankage located along the system.

Scurlock Permian

In May 1999, we completed the acquisition of Scurlock Permian LLC ("Scurlock") and certain other pipeline assets from Marathon Ashland Petroleum LLC. Including working capital adjustments and closing and financing costs, the cash purchase price was approximately \$141.7 million. Financing for the acquisition was provided through \$117.0 million of borrowings under our revolving credit facility and the sale of 1.3 million Class B common units to our former general partner for total cash consideration of \$25.0 million.

Scurlock, previously a wholly owned subsidiary of Marathon Ashland Petroleum, was engaged in crude oil transportation, gathering and marketing. The assets acquired included approximately 2,300 miles of active pipelines, numerous storage terminals and a fleet of trucks. The largest asset consists of an approximately 954-mile pipeline and gathering system located in the Spraberry Trend in West Texas that extends into Andrews, Glasscock, Martin, Midland, Regan and Upton Counties, Texas. The assets we acquired also included approximately one million barrels of crude oil linefill.

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 complimentary 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 where 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.

In connection with our acquisition activities, we routinely incur third party costs, which are capitalized and deferred pending final outcome of the transaction. Deferred costs associated with successful transactions are capitalized as part of the transaction, while deferred costs associated with unsuccessful transactions are expensed at the time of such final determination. We had a total of approximately \$0.2 million in deferred costs at June 30, 2004. 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.

Shutdown and Sale of Rancho Pipeline System

We acquired an interest in the Rancho Pipeline System in conjunction with the Shell acquisition. 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,

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we completed transactions whereby we transferred all of 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 all of our remaining ownership interest in the system to Kinder Morgan Texas Pipeline, L.P. for approximately \$870,000.

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 to a unit of El Paso Corporation 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 in connection with the sale of the linefill.

Description of Segments and Associated Assets

Our business activities are conducted through two primary segments, Pipeline Operations and Gathering, Marketing, Terminalling and Storage Operations. Our operations are conducted in approximately 40 states in the United States and six provinces in Canada. The majority of our operations are conducted in Texas, Oklahoma, California, Kansas and Louisiana and in the Canadian provinces of Alberta and Saskatchewan.

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

Pipeline Operations

As of June 30, 2004, we owned approximately 15,000 miles of gathering and mainline crude oil pipelines located throughout the United States and Canada. 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 and local laws and regulations, standards prescribed by the American Petroleum Institute and accepted industry practice. See " Regulation Pipeline and Storage Regulation."

Following is a description of our major pipeline assets in the United States and Canada, grouped by geographic location:

Southwest U.S.

Basin Pipeline System. We acquired an approximate 87% undivided joint interest in the Basin System in the Shell acquisition. 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 273,000 barrels per day (net to our interest) during the first six months of 2004. 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 size of the pipe ranges from 20 to 24 inches in diameter. The Basin 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. TEPPCO Partners, L.P. owns the remaining approximately 13% interest in 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 \$1.8 million 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"). See " Regulation Transportation Regulation."

West Texas Gathering System. The West Texas Gathering System is a common carrier crude oil pipeline system located in the heart of the Permian Basin producing area, and includes approximately 420 miles of crude oil mainlines and approximately 295 miles of associated gathering and lateral lines. The West Texas Gathering System has the capability to transport approximately 190,000 barrels per day. Total system volumes were approximately 80,000 barrels per day in the first six months of 2004. Chevron USA has agreed to transport its equity crude oil production from fields connected to the West Texas Gathering System on the system through July 2011 (representing approximately 18,000 barrels per day, or 21% of the total system volumes during 2003). The system also includes approximately 2.7 million barrels of crude oil storage capacity, located primarily in Monahans, Midland, Wink and Crane, Texas.

Permian Basin Gathering System. The Permian Basin System, acquired in the Shell acquisition, includes several gathering systems and trunk lines with connecting injection stations and storage facilities. In total, the system consists of 919 miles of pipe and primarily transports crude oil from wells in the Permian Basin to the Basin System. The Permian Basin System gathered approximately 48,000 barrels per day in the first six months of 2004. The Permian Basin System includes approximately 3.9 million barrels of crude oil storage capacity.

Spraberry Pipeline System. The Spraberry Pipeline System, acquired in the Scurlock acquisition, gathers crude oil from the Spraberry Trend of West Texas and transports it to Midland, Texas, where it interconnects with the West Texas Gathering System and other pipelines. The Spraberry Pipeline

System consists of approximately 954 miles of pipe of varying diameter, and has a throughput capacity of approximately 50,000 barrels of crude oil per day. The Spraberry Trend is one of the largest producing areas in West Texas, and we are one of the largest gatherers in the Spraberry Trend. For the first six months of 2004, the Spraberry Pipeline System gathered approximately 38,000 barrels per day of crude oil. The Spraberry Pipeline System also includes approximately 659,000 barrels of tank capacity located along the pipeline, including the recent expansion.

Dollarhide Pipeline System. The Dollarhide Pipeline System, acquired from Unocal Pipeline Company in October 2001, is a common carrier pipeline system that is located in West Texas. In the first six months of 2004, the Dollarhide Pipeline System delivered approximately 6,000 barrels of crude oil per day into the West Texas Gathering System. The system also includes approximately 55,000 barrels of crude oil storage capacity along the system.

Mesa Pipeline System. The Mesa Pipeline System, in which we acquired an 8.8% undivided interest from Unocal Corporation in May 2003, is located in the Permian Basin in West Texas, originating at Midland and terminating at Colorado City, and serves to complement our Basin Pipeline System. We have access to a net capacity of approximately 28,000 barrels of crude oil per day on the system. This system is operated by an affiliate of ChevronTexaco.

Iraan to Midland Pipeline System. The Iraan to Midland Pipeline System, acquired from a unit of Marathon Ashland Petroleum LLC in June 2003, is a 16-inch, 98-mile mainline crude oil pipeline that originates in Iraan, Texas and terminates in Midland, Texas. At Midland, the system has the ability to deliver crude oil to our Basin Pipeline System and to the Mesa Pipeline System. In the first six months of 2004, deliveries averaged approximately 22,000 barrels per day.

Iatan Gathering System. The Iatan gathering system, acquired from Navajo Refining Company, L.P. in March 2003, is located in the Permian Basin in West Texas and consists of approximately 360 miles of active crude oil gathering lines. During the first six months of 2004, volumes on this system averaged 22,000 barrels per day.

New Mexico Pipeline System. The New Mexico Pipeline System, included in the April 2004 Link transaction, is an extensive crude oil mainline and gathering system primarily located in Lea and Eddy Counties, New Mexico. The system consists of approximately 1,200 miles of active pipe and approximately 1.3 million barrels of associated storage. The system delivers primarily to the Basin Pipeline System, an Amoco Pipeline System, and the Kaston Pipeline system. For the second quarter of 2004, volumes averaged approximately 67,000 barrels per day.

Texas Pipeline System. The Texas Pipeline System, included in the April 2004 Link transaction, is an extensive crude oil mainline and gathering system delivering crude oil produced in the Permian Basin primarily to Midland, McCamey, and Colorado City, Texas. Also, included in the system is a 10" mainline from McCamey, Texas to Healdton, Oklahoma and approximately 2.0 million barrels of storage. For the second quarter of 2004, volumes averaged approximately 103,000 barrels per day.

Western U.S.

All American Pipeline System. The segment of the All American Pipeline that we retained following the sale of the line segment to El Paso is a common carrier crude oil pipeline system that transports crude oil produced from certain outer continental shelf, or OCS, fields offshore California to locations in California. This segment is subject to tariff rates regulated by the FERC.

We own and operate the segment of the system that 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, including the Unocap Pipeline System, the Shell Pipeline Company, L.P. and the Pacific Pipeline.

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 PXP and other producers, which 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 who 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 posted 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. At December 31, 2003, the tariffs averaged \$1.71 per barrel. Effective January 1, 2004, based on the contractual escalator, the average tariff increased to \$1.81 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 23% in 1999 to 17% in 2003, 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, offset somewhat 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 46,000 and 11,000 average daily barrels, respectively, for the first six months of 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 tariff revenues of approximately \$3.3 million, based on a tariff of \$1.81 per barrel.

In October 2004, 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. Such activities are not expected to have a significant impact on pipeline shipments on our All American Pipeline system in 2004. 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 and the six months ended June 30, 2004:

	Six Months Ended June 30, 2004	Year Ended December 31,				
		2003	2002	2001	2000	1999
		(barrels in thousands)				
Average daily volumes received from:						
Point Arguello (at Gaviota)	11	13	16	18	18	20
Santa Ynez (at Las Flores)	46	46	50	51	56	59
Total	57	59	66	69	74	79

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SVJ Gathering System. The SVJ Gathering System is connected to most of the major fields in the San Joaquin Valley. The SVJ Gathering System was constructed in 1987 with a design capacity of approximately 140,000 barrels per day. The system consists of a 16-inch pipeline that originates at the Belridge station and extends 45 miles south to a connection with the All American Pipeline at the Pentland station. The SVJ Gathering System also includes approximately 730,000 barrels of tank capacity, which can be used to facilitate movements along the system as well as to support our other activities.

The table below sets forth the historical volumes received into the SVJ Gathering System for the past five years and the six months ended June 30, 2004:

	Six Months Ended June 30, 2004	Year Ended December 31,				
		2003	2002	2001	2000	1999
(barrels in thousands)						
Total average daily volumes	73	78	73	61	60	84

Butte Pipeline System. We own an approximate 22% equity interest in Butte Pipe Line Company, which in turn owns the Butte Pipeline System, a 370-mile mainline system that runs from Baker, Montana to Guernsey, Wyoming. The Butte Pipeline System is connected to the Poplar Pipeline System, which in turn is connected to the Wascana Pipeline System, which is located in our Canadian Region and is wholly owned by us. The total system volumes for the Butte Pipeline System during the first six months of 2004 were approximately 66,000 barrels of crude oil per day (approximately 15,000 barrels per day, net to our 22% interest). The operator of the system is Bridger Pipeline.

North Dakota Systems. The North Dakota Systems, included in the April 2004 Link acquisition, consist of the Bowman-Baker Pipeline System, the Trenton Pipeline System and the North Dakota Gathering System. Aggregate volumes on the systems averaged approximately 46,000 barrels per day for the second quarter of 2004. The Bowman-Baker System is a 283-mile, FERC regulated common carrier pipeline system from Harding County, South Dakota to the Butte Pipeline System at Baker, Montana. The Trenton Pipeline System consists of 116 miles of active pipeline from Richland County, Montana to Williston County, North Dakota delivering crude to Enbridge's Portal Pipeline System. The North Dakota Gathering System consists of approximately 220 miles of active pipeline located in the Williston Basin region of North Dakota. The system delivers primarily to Tesoro pipeline for consumption at Tesoro's Mandan Refinery or to the Little Missouri Pipeline, a feeder of the Butte Pipeline System.

U.S. Gulf Coast

Sabine Pass Pipeline System. The Sabine Pass Pipeline System, acquired in the Scurlock acquisition, is a common carrier crude oil pipeline system. The Sabine Pass Pipeline System primarily gathers crude oil from onshore facilities of offshore production near Johnson's Bayou, Louisiana, and delivers it to tankage and barge loading facilities in Sabine Pass, Texas. The Sabine Pass Pipeline System consists of approximately 51 miles of pipe ranging from 4 to 10 inches in diameter and has a throughput capacity of approximately 26,000 barrels of crude oil per day. During the first six months of 2004, the system transported approximately 15,000 barrels of crude oil per day. The Sabine Pass Pipeline System also includes 245,000 barrels of tank capacity located along the pipeline.

Ferriday Pipeline System. The Ferriday Pipeline System, acquired in the Scurlock acquisition, is a common carrier crude oil pipeline system located in eastern Louisiana and western Mississippi. The Ferriday Pipeline System consists of approximately 570 miles of pipe ranging from 2 inches to 12 inches in diameter. During the first six months of 2004, the Ferriday Pipeline System delivered approximately 7,000 barrels of crude oil per day to third party pipelines that supplied refiners in the Midwest. The Ferriday Pipeline System also includes approximately 332,000 barrels of tank capacity located along the pipeline.

La Gloria Pipeline System. The La Gloria Pipeline System, acquired in the Scurlock acquisition, is a proprietary crude oil pipeline system that during the first six months of 2004, transported approximately 22,000 barrels of crude oil per day to Crown Central's refinery in Longview, Texas. Crown Central's deliveries are subject to a throughput and deficiency agreement, which extends through 2004.

Red River Pipeline System. The Red River Pipeline System, acquired in 2003, is a 334-mile crude oil pipeline system that originates at Sabine in East Texas, and terminates near Cushing, Oklahoma. The Red River system has a capacity of up to 22,000 barrels of crude oil per day, depending upon the type of crude oil being transported. During the first six months of 2004, the system transported approximately 11,000 barrels of crude oil per day. The system also includes approximately 645,000 barrels of crude oil storage capacity. In 2003, we completed a connection of the pipeline system to our Cushing Terminal.

ArkLaTex Pipeline System. The ArkLaTex Pipeline System, acquired from Link Energy (formerly EOTT Energy) in September 2003, consists of 240 miles of active crude oil gathering and mainline pipelines and connects to our Red River Pipeline System near Sabine, Texas. Also included in the transaction were 470,000 barrels of active crude oil storage capacity. During the first six months of 2004, volumes transported averaged 8,000 barrels per day.

Atchafalaya Pipeline System. The Atchafalaya Pipeline System, which we own 100% through three separate transactions in 2003, originates near Garden City, Louisiana and traverses east to its terminus near Gibson, Louisiana. The system consists of 35 miles of active 8-inch crude oil and condensate pipelines. During the first six months of 2004, the system transported approximately 15,000 barrels per day of crude oil and condensate.

Eugene Island Flowline System. The Eugene Island Flowline System ("EIFS") is a 57-mile offshore gathering pipeline located in the Eugene Island federal lease block area of the Gulf of Mexico. The system delivers crude oil gathered offshore to the Burns Terminal and to the Burns dock barge-loading facility in south Louisiana. The total system volumes for the EIFS during the first half of 2004 were approximately 12,000 barrels per day of crude oil.

Capline/Capwood Pipeline System. The Capline Pipeline System, in which we acquired a 22% undivided joint interest from Shell in March 2004, is a crude oil pipeline system that runs from St. James, Louisiana to Patoka, Illinois. The Capline Pipeline System consist of 633 miles of 40-inch pipe. 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, including refineries owned by ConocoPhillips, ExxonMobil, BP, MarathonAshland, CITGO and Premcor. 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, 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 the interest acquired by us. Since acquisition, throughput on the interest acquired averaged approximately 168,000 barrels per day. The Capwood Pipeline System, in which we acquired a 76% undivided joint interest from Shell in March 2004, is a crude oil pipeline system that runs from Patoka, Illinois to Wood River, Illinois. The Capwood Pipeline System consists of 57 miles of 20-inch pipe. 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 the interest acquired by us. The system has the ability to deliver crude at Wood River to several other PADD II refineries and pipelines, including those owned by Koch and ConocoPhillips. 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

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operatorship of the Capwood system from SPLC. Since acquisition, throughput on the interest acquired averaged approximately 130,000 barrels per day.

Mississippi/Alabama Pipeline System. The Mississippi/Alabama Pipeline System, included in the April 2004 Link transaction, consists of a 331 mile proprietary gathering system and a 355 mile common carrier trunk system delivering crude oil primarily to three local refineries and to the Capline Pipeline System at Liberty, Mississippi. Also included in this system is approximately 4.5 million barrels of storage. Approximately 2.8 million barrels of this storage capacity is located at a deep water terminal in Mobile, Alabama capable of handling tankers with a draft of approximately 37 feet. For the second quarter of 2004, volumes averaged approximately 38,000 barrels per day.

Southwest Louisiana Pipeline System. The Southwest Louisiana Pipeline System, included in the April 2004 Link transaction, consists of approximately 254 miles of primarily 6-10" pipe. The system originates in Rapides Parish, Louisiana and delivers to the Citgo refinery in Lake Charles, LA and to Nederland, Texas. For the second quarter of 2004, volumes averaged approximately 7,000 barrels per day.

Central U.S.

Oklahoma Pipeline System. The Oklahoma Pipeline System, included in the April 2004 Link transaction, consists of approximately 1,354 miles of active pipe, originating at various points in Oklahoma and terminating at Cushing, Oklahoma. In addition to the pipeline, there are approximately 1.7 million barrels of storage included in the system. For the second quarter of 2004, volumes averaged approximately 77,000 barrels per day.

Midcontinent Pipeline System. The Midcontinent Pipeline System, included in the April 2004 Link transaction, consists of approximately 1,200 miles of pipe, originating at various points in Nebraska, Kansas, and Colorado. Deliveries are primarily to Jayhawk pipeline and our Oklahoma Pipeline System. Also included in the system are approximately 0.4 million barrels of storage. For the second quarter of 2004, volumes averaged approximately 30,000 barrels per day.

Canada

Cal Ven Pipeline System. The Cal Ven Pipeline System, acquired in the Cal Ven acquisition in May 2004, is a crude oil pipeline that is located in Northern Alberta, Canada. The Cal Ven Pipeline System is comprised of approximately 195 miles of 8-inch and 10-inch gathering and mainline crude oil pipelines. The Cal Ven Pipeline System delivers crude oil into the Rainbow Pipeline System at Utikuma. At acquisition, the Cal Ven Pipeline System transported approximately 16,000 barrels per day.

Manito Pipeline System. The Manito Pipeline System, acquired in the Murphy acquisition, is a provincially regulated system located in Saskatchewan, Canada. The Manito Pipeline System is a 101-mile crude oil pipeline and a parallel 101-mile condensate pipeline that connects our North Saskatchewan Pipeline System and multiple gathering lines to the Enbridge system at Kerrobert. The Manito Pipeline System volumes were approximately 72,000 barrels of crude oil and condensate per day in the first six months of 2004.

Milk River Pipeline System. The Milk River Pipeline System, acquired in the Murphy acquisition, is a National Energy Board ("NEB") regulated system located in Alberta, Canada. The Milk River Pipeline System consists of three parallel 11-mile crude oil pipelines that connect the Bow River Pipeline in Alberta to the Cenex Pipeline at the United States border. The Milk River Pipeline System transported approximately 100,000 barrels of crude oil per day during the first six months of 2004.

North Saskatchewan Pipeline System. The North Saskatchewan Pipeline System, acquired in the Murphy acquisition, is a provincially regulated system located in Saskatchewan, Canada. We operate the

North Saskatchewan Pipeline System, which is a 34-mile crude oil pipeline and a parallel 34-mile condensate pipeline that connects to our Manito Pipeline at Dulwich. During the first six months of 2004, the North Saskatchewan Pipeline System delivered approximately 6,200 barrels of crude oil and condensate per day into the Manito Pipeline. Our ownership interest in the North Saskatchewan Pipeline System is approximately 69%.

Cactus Lake/Bodo Pipeline System. The Cactus Lake/Bodo Pipeline System, acquired in the Murphy acquisition, is located in Alberta and Saskatchewan, Canada. The Bodo portion of the system is NEB-regulated, and the remainder is provincially regulated. We operate the Cactus Lake/Bodo Pipeline System, which is a 55-mile crude oil pipeline and a parallel 55-mile condensate pipeline that connects to our storage and terminalling facility at Kerrobert. During the first six months of 2004, the Cactus Lake/Bodo Pipeline System transported approximately 25,000 barrels per day (approximately 3,200 barrels per day, net to our interest) of crude oil and condensate. Our ownership interest in the Cactus Lake segment is 15% and our ownership interest in the Bodo Pipeline is 100%. We also own various interests in the lateral lines in these systems.

Wascana Pipeline System. The Wascana Pipeline System, acquired in the Murphy acquisition, is an NEB-regulated system located in Saskatchewan, Canada. The Wascana Pipeline System is a 107-mile crude oil pipeline that connects to the Bridger Pipeline system at the United States border near Raymond, Montana. During the first six months of 2004, the Wascana Pipeline System transported approximately 8,000 barrels of crude oil per day.

Wapella Pipeline System. The Wapella Pipeline System is a 79 mile, NEB-regulated system located in southeastern Saskatchewan and southwestern Manitoba. During the first six months of 2004, the Wapella Pipeline System delivered approximately 14,000 barrels of crude oil per day to the Enbridge Pipeline at Cromer, Manitoba. The system also includes approximately 18,500 barrels of crude oil storage capacity.

South Saskatchewan Pipeline System. The South Saskatchewan Pipeline System, which was acquired in November 2003, originates approximately 75 miles southwest of Swift Current, Saskatchewan, and traverses north and east until it reaches its terminus at Regina. The system consists of a 158-mile, 16-inch mainline and 203 miles of gathering lines ranging in diameter from three to twelve inches. During the first six months of 2004, the system transported approximately 47,000 barrels of crude oil per day. At Regina, the system can deliver crude oil to the Enbridge Pipeline System and to local markets. In addition, the system can indirectly deliver crude oil into our Wascana Pipeline System.

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 provides us with the flexibility to optimize 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 and trading locations;

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transporting this 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 this 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 with lower margins compared to 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 and the six months ended June 30, 2004:

		Year Ended December 31,				
	Six Months Ended June 30, 2004	2003	2002	2001	2000	1999
		(barrels in thousands)				
Lease gathering	550	437	410	348	262	265
Bulk purchases ⁽¹⁾	136	90	68	46	28	138
Total volumes	686	527	478	394	290	403

(1) We have decreased the number of barrels previously disclosed in the "Bulk purchases" line for the 2002 period by approximately 12,000. The adjustment reflects an elimination of crude oil volumes improperly classified as bulk purchases.

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 full, 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.

Since 1998, we have had a marketing arrangement with Plains Resources, under which we have been the exclusive marketer and purchaser for all of Plains Resources' equity crude oil production (including its subsidiaries that conduct exploration and production activities). 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.

In December 2002, Plains Resources completed a spin-off to its stockholders of PXP. We currently have a marketing agreement with PXP for the majority 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. This fee is subject to adjustment every three years based upon then existing market conditions. We are currently negotiating an adjustment to the marketing fee, which we expect to be a downward adjustment. 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, at market prices for 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 and 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 that this policy was violated, and we incurred \$174.0 million in unauthorized trading losses, including associated costs and legal expenses. In 2000, we recognized an additional \$7.0 million charge related to the settlement of litigation for an amount in excess of established reserves.

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 United States 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 throughout the United States and Canada, concentrated primarily in Washington, California, Kansas, Michigan, Texas, Montana, Nebraska and the Canadian provinces of Alberta and Ontario. 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 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 our controlled 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 for resale and require significant extensions of credit by our suppliers of crude oil. In order to assure our ability to perform our obligations under crude oil purchase agreements, various credit arrangements are negotiated with our crude oil 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 market crude oil, 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 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, 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 \$0.05 per gallon 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, including tankage associated with our pipeline and gathering systems. 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

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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;

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

traders who make or take delivery under NYMEX contracts; and

producers and resellers that seek to increase their marketing alternatives.

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 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." In 1999, we completed our 1.1 million barrel Phase I expansion project, which increased the facility's total storage capacity to 3.1 million barrels. On July 1, 2002, we placed in service approximately 1.1 million barrels of tank capacity associated with our Phase II expansion of the Cushing Terminal, raising the facility's total storage capacity to approximately 4.2 million barrels. In January 2003, we placed in service our 1.1 million barrel Phase III expansion, and in July 2004, we completed our Phase IV expansion which increased the total capacity of our Cushing Terminal by 20%. The expansion 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. We believe that the facility can be further expanded to meet additional demand should market conditions warrant. 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 expected increase in the volumes as well as the varieties of foreign and domestic crude oil projected to be transported through the Cushing Interchange, we incorporated certain attributes into the 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 and we have sufficient land holdings in and around the Cushing Interchange on which to construct additional tankage. Our tankage in Cushing ranges in age from less than a year