PLAINS ALL AMERICAN PIPELINE LP
Form S-4
December 10, 2004

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As filed with the Securities and Exchange Commission on December 10, 2004

Registration No. 333-

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM S-4

**REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933**

PLAINS ALL AMERICAN PIPELINE, L.P.
PAA FINANCE CORP.*

(Exact Name of Registrant as Specified in its Charter)

Delaware	**4610**	**76-0582150**
Delaware	**4610**	**76-0669671**
(State or Other Jurisdiction of Incorporation or Organization)	(Primary Standard Industrial Classification Code Number)	(I.R.S. Employer Identification Number)

**333 Clay Street, Suite 1600
Houston, Texas 77002
(713) 646-4100**

(Address, Including Zip Code, and Telephone Number, including Area Code, of Registrant's Principal Executive Offices)

**Tim Moore
Vice President and General Counsel
333 Clay Street, Suite 1600
Houston, Texas 77002
(713) 646-4100**

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

Copy to:
**David P. Oelman
Vinson & Elkins L.L.P.
1001 Fannin Street, Suite 2300
Houston, Texas 77002
(713) 758-2222**

Approximate date of commencement of proposed sale to the public: As soon as practicable after the effective date of this Registration Statement.

If the securities being registered on this Form are being offered in connection with the formation of a holding company and there is compliance with General Instruction G, check the following box. o

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

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

CALCULATION OF REGISTRATION FEE

Title of Each Class of Securities to be Registered	Amount to be Registered	Proposed Maximum Offering Price per Note	Proposed Maximum Aggregate Offering Price	Amount of Registration Fee
4.750% Senior Notes due 2009	$175,000,000	100%	$175,000,000	$22,173
Guarantees[2]				
5.875% Senior Notes due 2016	$175,000,000	100%	$175,000,000	$22,173
Guarantees[2]				
Total	$350,000,000	100%	$350,000,000	$44,346

(1) Determined in accordance with Rule 457(f) under the Securities Act of 1933, as amended.

(2) No separate consideration will be received for the guarantees, and no separate fee is payable pursuant to Rule 457(a) under the Securities Act of 1933.

* Includes certain subsidiaries of Plains All American Pipeline, L.P. identified on the following pages.

Plains Marketing, L.P.
(Exact Name of Registrant As Specified In Its Charter)

Delaware	**76-0684572**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification Number)

Plains Pipeline, L.P.
(Exact Name of Registrant As Specified In Its Charter)

Texas	**76-0587185**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification Number)

Plains Marketing GP Inc.
(Exact Name of Registrant As Specified In Its Charter)

Delaware	**76-0684572**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification Number)

Plains Marketing Canada LLC
(Exact Name of Registrant As Specified In Its Charter)

Delaware	**76-0653735**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification Number)

Plains Marketing Canada, L.P.
(Exact Name of Registrant As Specified In Its Charter)

Canada	**892946211**
(State or Other Jurisdiction of Incorporation or Organization)	(GST Number)

PMC (Nova Scotia) Company
(Exact Name of Registrant As Specified In Its Charter)

Nova Scotia	**894798610**
(State or Other Jurisdiction of Incorporation or Organization)	(GST Number)

Basin Holdings GP LLC
(Exact Name of Registrant As Specified In Its Charter)

Delaware	**13-4204744**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification Number)

Basin Pipeline Holdings, L.P.
(Exact Name of Registrant As Specified In Its Charter)

Delaware	**13-4204757**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification Number)

Rancho Holdings GP LLC
(Exact Name of Registrant As Specified In Its Charter)

Delaware	**13-4204734**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification Number)

Rancho Pipeline Holdings, L.P.
(Exact Name of Registrant As Specified In Its Charter)

Delaware	**13-4204750**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification Number)

The Registrants hereby amend this Registration Statement on such date or dates as may be necessary to delay its effective date until the Registrants 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 December 10, 2004

Prospectus

Plains All American Pipeline, L.P.
PAA Finance Corp.

Offer to Exchange up to
$175,000,000 of 4.750% Senior Notes due 2009
for
$175,000,000 of 4.750% Senior Notes due 2009
that have been Registered under the Securities Act of 1933
and
Offer to Exchange up to
$175,000,000 of 5.875% Senior Notes due 2016
for
$175,000,000 of 5.875% Senior Notes due 2016
that have been Registered under the Securities Act of 1933

Terms of the Exchange Offers

We are offering to exchange up to $175,000,000 of our outstanding 4.750% Senior Notes due 2009 ("2009 Notes") and up to $175,000,000 of our outstanding 5.875% Senior Notes due 2016 ("2016 Notes," and together with the 2009 Notes, the "Outstanding Notes") for new Notes with substantially identical terms that have been registered under the Securities Act and are freely tradable.

We will exchange for an equal principal amount of new Notes all outstanding Notes of the same series that you validly tender and do not validly withdraw before the exchange offers expire.

Each exchange offer will expire at 5:00 p.m., New York City time, on , 200 , unless extended. We do not currently intend to extend either exchange offer.

Tenders of outstanding Notes may be withdrawn at any time prior to the expiration of the applicable exchange offer.

Each exchange of outstanding Notes for new Notes will not be a taxable event for U.S. federal income tax purposes.

Terms of the 2009 Notes Offered in the Exchange Offer

Maturity
The 2009 Notes will mature on August 15, 2009.

Interest
We will pay interest on the 2009 Notes semi-annually in arrears on February 15 and August 15 of each year, beginning February 15, 2005.

Interest will accrue from August 12, 2004.

Redemption
We may redeem the 2009 Notes, in whole or in part, at any time at a price equal to 100% of the principal amount of the 2009 Notes to be redeemed plus a make-whole premium described in this prospectus, plus accrued and unpaid interest, if any, to the redemption date.

Ranking
The 2009 Notes are unsecured. The 2009 Notes are general senior unsecured obligations of the issuers and will rank equally with the Notes of the other series and with the existing and future senior unsecured indebtedness of the issuers.

Terms of the 2016 Notes Offered in the Exchange Offer

Maturity

The 2016 Notes will mature on August 15, 2016.

Interest

We will pay interest on the 2016 Notes semi-annually in arrears on February 15 and August 15 of each year, beginning February 15, 2005.

Interest will accrue from August 12, 2004.

Redemption

We may redeem the 2016 Notes, in whole or in part, at any time at a price equal to 100% of the principal amount of the 2016 Notes to be redeemed plus a make-whole premium described in this prospectus, plus accrued and unpaid interest, if any, to the redemption date.

Ranking

The 2016 Notes are unsecured. The 2016 Notes are general senior unsecured obligations of the issuers and will rank equally with the Notes of the other series and with the existing and future senior unsecured indebtedness of the issuers.

Please read "Risk Factors" on page 7 for a discussion of factors you should consider before participating in the exchange offers.

These securities have not been approved or disapproved by the Securities and Exchange Commission or any state securities commission nor has the Securities and Exchange Commission passed upon the accuracy or adequacy of this prospectus. Any representation to the contrary is a criminal offense.

The date of this prospectus is , 2004.

This prospectus is part of a registration statement we filed with the Securities and Exchange Commission, or SEC. In making your investment decision, you should rely only on the information contained in this prospectus and in the accompanying letters of transmittal. We have not authorized anyone to provide you with any other information. If you receive any unauthorized information, you must not rely on it. We are not making offers to sell these securities in any state where the offers are not permitted. You should not assume that the information contained in this prospectus is accurate as of any date other than the date on the front cover of this prospectus.

Each broker-dealer that receives the Notes for its own account pursuant to these exchange offers must acknowledge in the applicable letter of transmittal that it will deliver a prospectus in connection with any resale of the Notes. This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of the Notes received in exchange for outstanding Notes where such outstanding Notes were acquired by such broker-dealer as a result of market-making activities or other trading activities. We have agreed to make this prospectus available for a period of one year from the expiration date of these exchange offers to any broker-dealer for use in connection with any such resale. See "Plan of Distribution."

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PROSPECTUS SUMMARY

This summary may not contain all the information that may be important to you. You should read this entire prospectus before deciding to participate in the exchange offers. You should carefully consider the information set forth under "Risk Factors." In addition, certain statements include forward-looking information which involves risks and uncertainties. Please read "Forward-Looking Statements." References to the "Notes" in this prospectus include both the outstanding Notes and the new Notes.

In this prospectus, 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.

Plains All American Pipeline, L.P.

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.

Our executive offices are located at 333 Clay Street, Suite 1600, Houston, Texas 77002 and our telephone number is (713) 646-4100.

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.

The Exchange Offers

On August 12, 2004, we completed private offerings of $175 million aggregate principal amount of our 4.750% senior notes due 2009 ("2009 Notes") and $175 million aggregate principal amount of our 5.875% senior notes due 2016 ("2016 Notes" and together with the 2009 Notes, the "outstanding Notes"). We entered into registration rights agreements with the initial purchasers in those offerings, in which we agreed to deliver to you this prospectus and to use our reasonable best efforts to complete the exchange offers within 240 days after the date we issued the outstanding Notes.

Exchange Offers	We are offering to exchange new Notes (the "New Notes") for: up to $175 million principal amount of our 4.750% 2009 Notes that have been registered under the Securities Act of 1933 (the "Securities Act"), for an equal amount of our outstanding 2009 Notes; and up to $175 million principal amount of our 5.875% 2016 Notes that have been registered under the Securities Act for an equal amount of our outstanding 2016 Notes to satisfy our obligations under the registration rights agreements that we entered into when we issued the outstanding Notes in transactions exempt from registration under the Securities Act. The terms of each series of the new Notes are substantially identical to those terms of each series of the outstanding Notes, except that the transfer restrictions, registration rights and provisions for additional interest relating to the outstanding Notes do not apply to the new Notes.
Expiration Date	Each exchange offer will expire at 5:00 p.m. New York City time, on , 200 , unless we decide to extend either exchange offer. We may extend one exchange offer without extending the other.
Condition to the Exchange Offers	The registration rights agreements do not require us to accept outstanding Notes for exchange if the applicable exchange offer or the making of any exchange by a holder of the outstanding Notes would violate any applicable law or interpretation of the staff of the SEC. A minimum aggregate principal amount of outstanding Notes being tendered is not a condition to either exchange offer.
Procedures for Tendering Outstanding Notes	To participate in an exchange offer, you must follow the procedures established by The Depository Trust Company, which we call "DTC," for tendering notes held in book-entry form. These automated tender offer program procedures, which we call "ATOP," require that (i) the exchange agent receive, prior to the expiration date of the applicable exchange offer, a computer generated message known as an "agent's message" that is transmitted through ATOP and (ii) DTC confirms that: DTC has received your instructions to exchange your Notes, and

	you agree to be bound by the terms of the applicable letter of transmittal.
	For more information on tendering your outstanding Notes, please refer to the sections in this prospectus entitled "Exchange Offers Terms of the Exchange Offers" and " Procedures for Tendering."
Guaranteed Delivery Procedures	None.
Withdrawal of Tenders	You may withdraw your tender of outstanding Notes under either exchange offer at any time prior to the expiration date. To withdraw, you must submit a notice of withdrawal to the exchange agent using ATOP procedures before 5:00 p.m. New York City time on the expiration date of the exchange offer. Please read "Exchange Offers Withdrawal of Tenders."
Acceptance of Outstanding Notes and Delivery of New Notes	If you fulfill all conditions required for proper acceptance of outstanding Notes, we will accept any and all outstanding Notes that you properly tender in the applicable exchange offer on or before 5:00 p.m. New York City time on the expiration date. We will return to you, without expense as promptly as practicable after the expiration date, any outstanding Note that we do not accept for exchange. We will deliver the new Notes as promptly as practicable after the expiration date and acceptance of the outstanding Notes for exchange. Please refer to the section in this prospectus entitled "Exchange Offers Terms of the Exchange Offers."
Fees and Expenses	We will bear all expenses related to each exchange offer. Please refer to the section in this prospectus entitled "Exchange Offers Fees and Expenses."
Use of Proceeds	The issuance of the new Notes will not provide us with any new proceeds. We are making these exchange offers solely to satisfy our obligations under the registration rights agreements.
Consequences of Failure to Exchange Outstanding Notes	If you do not exchange your outstanding Notes in the applicable exchange offer, you will no longer be able to require us to register the outstanding Notes under the Securities Act except in the limited circumstances provided under the applicable registration rights agreement. In addition, you will not be able to resell, offer to resell or otherwise transfer the outstanding Notes unless we have registered the outstanding Notes under the Securities Act, or unless you resell, offer to resell or otherwise transfer them under an exemption from the registration requirements of, or in a transaction not subject to, the Securities Act.
Tax Considerations	The exchange of new Notes for 2009 Notes and the exchange of new Notes for 2016 Notes should not be a taxable event for U.S. federal income tax purposes. Please read "Tax Considerations."

Exchange Agent	We have appointed Wachovia Bank, National Association, as exchange agent for each of the exchange offers. You should direct questions and requests for assistance and requests for additional copies of this prospectus or the letters of transmittal to the exchange agent addressed as follows: Wachovia Bank, National Association, Customer Information Center, Corporate Trust Operations NC1153, 1525 West W. T. Harris Blvd. Charlotte, North Carolina 28288-1153. Eligible institutions may make requests by facsimile at (704) 590-7628.

Terms of the New Notes

The new Notes will be identical to the outstanding Notes except that the new Notes are registered under the Securities Act and will not have transfer restrictions, registration rights or provisions for additional interest. The new Notes will evidence the same debt as the outstanding Notes, and the same indenture will govern the new Notes and the outstanding Notes.

The following summary contains basic information about the new Notes and is not intended to be complete. It does not contain all the information that is important to you. For a more complete understanding of the notes, please refer to the section of this prospectus entitled "Description of Notes."

Issuers	Plains All American Pipeline, L.P. and PAA Finance Corp. PAA Finance Corp., a Delaware corporation, is an indirect wholly owned subsidiary of Plains All American Pipeline, L.P. that has been organized for the purpose of co-issuing our existing notes, the Notes offered hereby, and the notes issued in any future offerings. PAA Finance Corp. does not have any operations of any kind and will not have any revenue other than as may be incidental to its activities as a co-issuer of the Notes.
Notes Offered	$175 million aggregate principal amount of the 2009 Notes. $175 million aggregate principal amount of the 2016 Notes.
Maturity Dates	August 15, 2009 for the 2009 Notes. August 15, 2016 for the 2016 Notes.
Interest Payment Dates	We will pay interest on the Notes of each series semi-annually in arrears on February 15 and August 15 of each year, beginning on February 15, 2005.
Optional Redemption	We may redeem the Notes of either series, in whole or in part, at any time and from time to time at a price equal to the greater of (i) 100% of the principal amount of Notes to be redeemed or (ii) the sum of the present values of the remaining scheduled payments of principal of and interest on the Notes to be redeemed discounted to the redemption date on a semi-annual basis at the Adjusted Treasury Rate (as defined herein) plus 20 basis points, in the case of the 2009 Notes, and 25 basis points, in the case of the 2016 Notes plus, in each case, accrued interest to the date of redemption. See "Description of Notes Optional Redemption."
Guarantees	Initially, all payments with respect to the Notes (including principal and interest) are fully and unconditionally guaranteed, jointly and severally, by substantially all of our existing subsidiaries. In the future, our subsidiaries that guarantee other indebtedness of ours or another subsidiary must also guarantee the Notes. The guarantees are also subject to release in certain circumstances. The guarantees of each series are general unsecured obligations of the subsidiary guarantors and rank equally with the guarantees of the other series and with any existing and future senior unsecured indebtedness of the subsidiary guarantors.

Ranking	The Notes are general senior unsecured obligations of the issuers and rank equally with the Notes of the other series and with the existing and future senior unsecured indebtedness of the issuers.
Certain Covenants	The indenture governing the Notes contains covenants for your benefit. These covenants restrict our ability and our restricted subsidiaries' ability, with certain exceptions, to: incur liens on principal properties to secure debt; engage in sale-leaseback transactions; or merge or consolidate with another entity or sell, lease or transfer substantially all of our properties or assets to another entity.
Transfer Restrictions; Absence of a Public Market for the Notes	The new Notes generally will be freely transferable, but will also be new securities for which there will not initially be a market. There can be no assurance as to the development or liquidity of any market for the new Notes.
Form of New Notes	The new Notes will be represented by one or more global notes. The global notes of each series will be deposited with the trustee, as custodian for DTC. The global notes of each series will be shown on, and transfers of the global notes of each series will be effected only through, records maintained in book-entry form by DTC and its direct and indirect participants.
Same-Day Settlement	The new Notes will trade in DTC's Same Day Funds Settlement System until maturity or redemption. Therefore, secondary market trading activity in the new Notes will be settled in immediately available funds.
Trading	We do not expect to list the new Notes for trading on any securities exchange.
Trustee, Registrar and Exchange Agent	Wachovia Bank, National Association.
Governing Law	The new Notes and the indenture relating to the new Notes will be governed by, and construed in accordance with, the laws of the State of New York.

RISK FACTORS

In addition to the other information set forth elsewhere in this prospectus, you should carefully consider the risks relating to our partnership, the exchange offers and the Notes described below before deciding whether to participate in the exchange offers.

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, any event that disrupts our anticipated physical supply of crude oil could expose us to risk of loss resulting from price changes. Moreover, we are exposed to some risks that are not hedged, including certain basis risks and price risks on certain of our inventory, such as pipeline linefill, which must be maintained in order to transport crude oil on our pipelines. In addition, we engage in a controlled trading program for up to an aggregate of 500,000 barrels of crude oil. Although this activity is monitored independently by our risk management function, it exposes us to price risks within predefined limits and authorizations.

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

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

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

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

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

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

Any acquisition involves potential risks, including:

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

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

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

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

The profitability of our pipeline operations depends on the volume of crude oil shipped 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 system, would change annualized segment profit by approximately $1.0 million. In addition, we estimate that an average 10,000 barrel per day variance on the Capline Pipeline System, equivalent to an approximate 7% volume variance on that system, would change annualized segment profit by approximately $1.5 million.

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

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

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

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

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

Our competitors include other crude oil pipelines, the major integrated oil companies, their marketing affiliates, and independent gatherers, brokers and marketers of widely varying sizes, financial resources and experience. Some of these competitors have capital resources many times greater than ours and control greater supplies of crude oil. We estimate that a $0.01 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 counterparties or that there will not be an unanticipated deterioration in their credit worthiness, which could have an adverse impact on us.

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

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

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

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

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

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

Fluctuations in demand can negatively affect our operating results.

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

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

As of September 30, 2004, our total outstanding long-term debt was approximately $837.6 million. Various limitations in our indebtedness may reduce our ability to incur additional debt, to engage in some transactions and to capitalize on business opportunities. Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions.

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

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

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 pay our debt service obligations.

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 pay our debt service obligations, including the New Notes.

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 Related to the Exchange Offers and the Notes

If you do not properly tender your outstanding Notes, you will continue to hold unregistered outstanding Notes and your ability to transfer outstanding Notes will be adversely affected.

We will only issue new Notes in exchange for outstanding Notes that you timely and properly tender. Therefore, you should allow sufficient time to ensure timely delivery of the outstanding Notes and you should carefully follow the instructions on how to tender your outstanding Notes. Neither we nor the exchange agent is required to tell you of any defects or irregularities with respect to your tender of outstanding Notes.

If you do not exchange your outstanding Notes for new Notes pursuant to the applicable exchange offer, the outstanding Notes you hold will continue to be subject to the existing transfer restrictions. In general, you may not offer or sell the outstanding Notes except under an exemption from, or in a transaction not subject to, the Securities Act and applicable state securities laws. We do not plan to register outstanding Notes under the Securities Act unless our registration rights agreements with the initial purchasers of the outstanding Notes require us to do so. Further, if you continue to hold any outstanding Notes after the applicable exchange offer is consummated, you may have trouble selling them because there will be fewer Notes outstanding.

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets.

We are a holding company, and our subsidiaries conduct all of our operations and own all of our operating assets. We have no significant assets other than the partnership interests and the equity in our subsidiaries. As a result, our ability to make required payments on the Notes depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, credit facilities and applicable state partnership laws and other laws and regulations. Pursuant to the credit facilities, we may be required to establish cash reserves for the future payment of principal and interest on the amounts outstanding under the credit facilities. If we are unable to obtain the funds necessary to pay the principal amount at maturity of either series of the Notes, we may be required to adopt one or more alternatives, such as a refinancing of the Notes. We cannot assure you that we would be able to refinance either series of the Notes.

Your right to receive payments on the Notes and the guarantees is unsecured and will be effectively subordinated to our existing and future secured indebtedness as well as to any existing and future indebtedness of our subsidiaries that do not guarantee the Notes.

The Notes are effectively subordinated to claims of our secured creditors, and the guarantees are effectively subordinated to the claims of our secured creditors as well as the secured creditors of our subsidiary guarantors. Although substantially all of our subsidiaries, other than PAA Finance Corp., the co-issuer of the Notes, will initially guarantee the Notes, in the future, under certain circumstances, the guarantees are subject to release and we may have subsidiaries that are not guarantors. In that case, the Notes would be effectively subordinated to the claims of all creditors, including trade creditors and tort claimants, of our subsidiaries that are not guarantors. In the event of the insolvency, bankruptcy, liquidation, reorganization, dissolution or winding up of the business of a subsidiary that is not a guarantor, creditors of that subsidiary would generally have the right to be paid in full before any distribution is made to us or the holders of the Notes.

Our leverage may limit our ability to borrow additional funds, comply with the terms of our indebtedness or capitalize on business opportunities.

Our leverage is significant in relation to our partners' capital. Various limitations in our credit agreements and other debt instruments 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.

Our leverage could have important consequences to investors in the Notes. We will require substantial cash flow to meet our principal and interest obligations with respect to the Notes and our other consolidated indebtedness. Our ability to make scheduled payments, to refinance our obligations with respect to our indebtedness or our ability to obtain additional financing in the future will depend on our financial and operating performance, which, in turn, is subject to prevailing economic conditions and to financial, business and other factors. We believe that we will have sufficient cash flow from operations and available borrowings under our bank credit facility to service our indebtedness, although the principal amount of the Notes of each series will likely need to be refinanced at maturity in whole or in part. However, a significant downturn in the hydrocarbon industry or other development adversely affecting our cash flow could materially impair our ability to service our indebtedness. If our cash flow and capital resources are insufficient to fund our debt service obligations, we may be forced to refinance all or a portion of our debt or sell assets. We cannot assure you that we would be able to refinance our existing indebtedness or sell assets on terms that are commercially reasonable. In addition, if one or more rating agencies were to lower our debt ratings, we could be required by some of our counterparties to post additional collateral, which would reduce our available liquidity and cash flow.

Our leverage may adversely affect our ability to fund future working capital, capital expenditures and other general partnership requirements, future acquisition, construction or development activities, or to otherwise fully realize the value of our assets and opportunities because of the need to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness or to comply with any restrictive terms of our indebtedness. Our leverage may also make our results of operations more susceptible to adverse economic and industry conditions by limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate and may place us at a competitive disadvantage as compared to our competitors that have less debt.

A court may use fraudulent conveyance considerations to void or subordinate the subsidiary guarantees.

Various applicable fraudulent conveyance laws have been enacted for the protection of creditors. A court may use fraudulent conveyance laws to subordinate or void the subsidiary guarantees of the Notes issued by any of our subsidiary guarantors. It is also possible that under certain circumstances a court could hold that the direct obligations of a subsidiary guaranteeing the Notes could be superior to the obligations under that guarantee.

A court could void or subordinate the guarantee of the Notes by any of our subsidiaries in favor of that subsidiary's other debts or liabilities to the extent that the court determined either of the following were true at the time the subsidiary issued the guarantee:

- that subsidiary incurred the guarantee with the intent to hinder, delay or defraud any of its present or future creditors or that subsidiary contemplated insolvency with a design to favor one or more creditors to the total or partial exclusion of others; or
- that subsidiary did not receive fair consideration or reasonable equivalent value for issuing the guarantee and, at the time it issued the guarantee, that subsidiary:
  - was insolvent or rendered insolvent by reason of the issuance of the guarantee;
  - was engaged or about to engage in a business or transaction for which the remaining assets of that subsidiary constituted unreasonably small capital; or
  - intended to incur, or believed that it would incur, debts beyond its ability to pay such debts as they matured.

The measure of insolvency for purposes of the foregoing will vary depending upon the law of the relevant jurisdiction. Generally, however, an entity would be considered insolvent for purposes of the foregoing if the sum of its debts, including contingent liabilities, were greater than the fair saleable value of all of its assets at a fair valuation, or if the present fair saleable value of its assets were less than the amount that would be required to pay its probable liability on its existing debts, including contingent liabilities, as they become absolute and matured.

Among other things, a legal challenge of a subsidiary's guarantee of the Notes on fraudulent conveyance grounds may focus on the benefits, if any, realized by that subsidiary as a result of our issuance of the Notes. To the extent a subsidiary's guarantee of the Notes is voided as a result of fraudulent conveyance or held unenforceable for any other reason, the Note holders would cease to have any claim in respect of that guarantee.

Your ability to transfer the Notes may be limited by the absence of a trading market.

The Notes will be new securities for which currently there is no trading market. We do not currently intend to apply for listing of the Notes on any securities exchange or stock market. The liquidity of any market for the Notes of either series will depend on the number of holders of those Notes, the interest of securities dealers in making a market in those Notes and other factors. Accordingly, we cannot assure you as to the development or liquidity of any market for the Notes of either series.

We do not have the same flexibility as other types of organizations to accumulate cash, which may limit cash available to service the Notes or to repay them at maturity.

Unlike a corporation, our partnership agreement requires us to distribute, on a quarterly basis, 100% of our available cash to our unitholders of record and to our general partner. Available cash is generally all of our cash receipts adjusted for cash distributions and net changes to reserves. Our general partner will determine the amount and timing of such distributions and has broad discretion to establish and make additions to our reserves or the reserves of our operating partnerships in amounts the general partner determines in its reasonable discretion to be necessary or appropriate:

- to provide for the proper conduct of our business and the businesses of our operating partnerships (including reserves for future capital expenditures and for our anticipated future credit needs),

- to provide funds for distributions to our unitholders and the general partner for any one or more of the next four calendar quarters, or

- to comply with applicable law or any of our loan or other agreements.

Although our payment obligations to our unitholders are subordinate to our payment obligations to you, the value of our units will decrease in direct correlation with decreases in the amount we distribute per unit. Accordingly, if we experience a liquidity problem in the future, we may not be able to issue equity to recapitalize.

USE OF PROCEEDS

Each exchange offer is intended to satisfy our obligations under the related registration rights agreement. We will not receive any cash proceeds from the issuance of the new Notes in the exchange offers. In consideration for issuing the new Notes as contemplated by this prospectus, we will receive outstanding Notes in a like principal amount. The form and terms of the new Notes are identical in all respects to the form and terms of the outstanding Notes, except the new Notes do not include certain transfer restrictions, registration rights or provisions for additional interest. Outstanding Notes surrendered in exchange for the new Notes will be retired and cancelled and will not be reissued. Accordingly, the issuance of the new Notes will not result in any change in our outstanding indebtedness.

RATIO OF EARNINGS TO FIXED CHARGES

The ratio of earnings to fixed charges for each of the periods indicated are as follows:

		Year Ended December 31,				
	Nine Months Ended September 30, 2004	2003	2002	2001	2000[2]	1999[2][3]
RATIO OF EARNINGS TO FIXED CHARGES[1]	3.77x	2.39x	2.77x	2.26x	3.33x	

(1) For purposes of computing the ratio of earnings to fixed charges, "earnings" consist of pretax income from continuing operations plus fixed charges (excluding capitalized interest). "Fixed charges" represent interest incurred (whether expensed or capitalized), amortization of debt expense, and that portion of rental expense on operating leases deemed to be the equivalent of interest.

(2) The 1999 and 2000 periods include losses of $1.5 million and $15.1 million, respectively, related to early extinguishment of debt previously classified as extraordinary items. Effective with our adoption of SFAS 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections" in January 2003, such items are included in income from continuing operations.

(3) In 1999, available earnings failed to cover fixed charges by $103.4 million.

EXCHANGE OFFERS

We sold the outstanding Notes on August 12, 2004, pursuant to a purchase agreement dated as of August 5, 2004, by and among us, PAA Finance Corp., certain of our subsidiaries and the initial purchasers named therein. The outstanding Notes were subsequently offered by the initial purchasers to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to non-U.S. persons pursuant to Regulation S under the Securities Act.

Purpose and Effect of the Exchange Offers

In connection with the issuance of the outstanding Notes, we entered into registration rights agreements with respect to each series of Notes. Under the registration rights agreements, we agreed to use our reasonable best efforts to:

- within 120 days of the original issuance of the Notes on August 12, 2004, file a registration statement with the SEC with respect to a registered offer to exchange the outstanding Notes for new Notes substantially identical to such Notes of such series except that the new Notes will not contain terms with respect to transfer restrictions, registration rights or provisions for additional interest;

- cause the registration statement to be declared effective within 210 days of the original issuance of the outstanding Notes;

- to consummate the exchange of the outstanding Notes for new Notes within 240 days of the original issuance of the outstanding Notes;

- promptly following the effectiveness of the registration statement, offer the new Notes in exchange for surrender of the outstanding Notes; and

- keep the exchange offers open for not less than 20 business days (or longer if required by applicable law) after the date notice of the exchange offers is mailed to the holders of the outstanding Notes.

We have fulfilled the agreements described in the first preceding bullet point and are now offering eligible holders of the outstanding Notes the opportunity to exchange their outstanding Notes for new Notes registered under the Securities Act. Holders are eligible if they are not prohibited by any law or policy of the SEC from participating in each exchange offer. The new Notes will be substantially identical to the outstanding Notes except that the new Notes will not contain terms with respect to transfer restrictions, registration rights or additional interest.

Under limited circumstances, we agreed to use our reasonable best efforts to cause the SEC to declare effective a shelf registration statement for the resale of the outstanding Notes. We also agreed to use our reasonable best efforts to keep the shelf registration statement effective for up to two years after its effective date. The circumstances include if:

- a change in law or applicable interpretations thereof by the staff of the SEC do not permit us to effect the exchange offers;

- for any other reason the applicable exchange offer is not consummated within 240 days from the date of the original issuance of the applicable series of outstanding Notes;

- any initial purchaser notifies us that outstanding Notes held by it are not eligible to be exchanged for new Notes in the applicable exchange offer and are held by it following consummation of the applicable exchange offer; or

- any holder other than an initial purchaser is not eligible to participate in the applicable exchange offer.

Subject to certain exceptions, we will pay additional cash interest on the applicable outstanding Notes if:

- the registration statement is not filed with the SEC on or before the 120th day after the original issuance of the outstanding Notes;
- the registration statement is not declared effective by the SEC on or before the 210th day of the original issuance of the outstanding Notes;
- the exchange offers are not consummated on or before the 240th day of the original issuance of the outstanding Notes;
- obligated to file a shelf registration statement, we fail to file the shelf registration statement with the SEC on or prior to the 120th day after the date on which the obligation to file a shelf registration statement arises;
- obligated to file a shelf registration statement, the shelf registration statement is not declared effective on or prior to the 210th day after the date on which the obligation to file a shelf registration statement arises; or
- after this registration statement or the shelf registration statement, as the case may be, is declared effective, such registration statement thereafter ceases to be effective (subject to certain exceptions) (each such event referred to in the preceding clauses being a "registration default").

Such additional interest will be payable from and including the date on which any such registration default occurs to the date on which all registration defaults have been cured.

The rate of the additional interest will be 0.25% per annum for the first 90-day period immediately following the occurrence and during the continuation of the registration default, and such rate will increase by an additional 0.25% per annum for each subsequent 90-day period until all registration defaults have been cured, up to a maximum additional interest rate of 0.50% per annum. We will pay such additional interest on regular interest payment dates. Such additional interest will be in addition to any other interest payable from time to time with respect to the outstanding Notes and the new Notes.

Upon the filing or effectiveness of this registration statement, the consummation of the exchange offers, the filing or effectiveness of a shelf registration statement, or the effectiveness of a succeeding registration statement, as the case may be, the interest rate borne by the Notes from the date of such filing, effectiveness or consummation, as the case may be, will be reduced to the original interest rate. However, if after any such reduction in interest rate, a different event specified in the clauses above occurs, the interest rate may again be increased pursuant to the preceding provisions.

To exchange your outstanding Notes for transferable new Notes in the applicable exchange offer, you will be required to represent that at the time of the consummation of the applicable exchange offer:

- any new Notes will be acquired in the ordinary course of your business;
- you have no arrangement or understanding with any person or entity to participate in the distribution of the new Notes;
- you are not engaged in and do not intend to engage in the distribution of the new Notes;
- if you are a broker-dealer that will receive new Notes for your own account in exchange for outstanding Notes, you acquired those notes as a result of market-making activities or other trading activities and you will deliver a prospectus, as required by law, in connection with any resale of such new Notes; and

you are not our "affiliate," as defined in Rule 405 of the Securities Act.

In addition, we may require you to provide information to be used in connection with the shelf registration statement to have your outstanding Notes included in the shelf registration statement. A holder who sells outstanding Notes under the shelf registration statement generally will be required to be named as a selling securityholder in the related prospectus and to deliver a prospectus to purchasers. Such a holder will also be subject to the civil liability provisions under the Securities Act in connection with such sales and will be bound by the provisions of the registration rights agreement that are applicable to such a holder, including indemnification obligations.

The description of the registration rights agreements contained in this section is a summary only. For more information, you should review the provisions of the registration rights agreements that we filed with the SEC as an exhibit to the registration statement of which this prospectus is a part.

Resale of New Notes

Based on no action letters of the SEC staff issued to third parties, we believe that new Notes may be offered for resale, resold and otherwise transferred by you without further compliance with the registration and prospectus delivery provisions of the Securities Act if:

- you are not our "affiliate" within the meaning of Rule 405 under the Securities Act;
- such new Notes are acquired in the ordinary course of your business; and
- you do not intend to participate in a distribution of the new Notes.

The SEC, however, has not considered either exchange offer for the new Notes in the context of a no action letter, and the SEC may not make a similar determination as in the no action letters issued to these third parties.

If you tender in an exchange offer with the intention of participating in any manner in a distribution of the new Notes, you

- cannot rely on such interpretations by the SEC staff; and
- must comply with the registration and prospectus delivery requirements of the Securities Act in connection with a secondary resale transaction.

Unless an exemption from registration is otherwise available, any security holder intending to distribute new Notes should be covered by an effective registration statement under the Securities Act. The registration statement should contain the selling securityholder's information required by Item 507 of Regulation S-K under the Securities Act.

This prospectus may be used for an offer to resell, resale or other retransfer of new Notes only as specifically described in this prospectus. Failure to comply with the registration and prospectus delivery requirements by a holder subject to these requirements could result in that holder incurring liability for which it is not indemnified by us. If you are a broker-dealer, you may participate in an exchange offer only if you acquired the outstanding Notes as a result of market-making activities or other trading activities. Each broker-dealer that receives new Notes for its own account in exchange for outstanding Notes, where such outstanding Notes were acquired by such broker-dealer as a result of market-making activities or other trading activities, must acknowledge in the applicable letter of transmittal that it will deliver a prospectus in connection with any resale of the new Notes. Please read the section captioned "Plan of Distribution" for more details regarding the transfer of new Notes.

Terms of the Exchange Offers

Subject to the terms and conditions described in this prospectus and in the applicable letter of transmittal, we will accept for exchange any outstanding Notes properly tendered and not withdrawn prior to 5:00 p.m. New York City time on the expiration date. We will issue new Notes in principal

amount equal to the principal amount of outstanding Notes of the same series surrendered under the applicable exchange offer. Outstanding Notes may be tendered only for new Notes and only in minimum principal amounts of $2,000 and integral multiples of $2,000.

Neither exchange offer is conditioned upon any minimum aggregate principal amount of outstanding Notes being tendered for exchange. Each exchange offer will be conducted independently from the other exchange offer, and consummation of one exchange offer will not be conditioned upon consummation of the other.

As of the date of this prospectus, $175 million in aggregate principal amount of the 2009 Notes are outstanding and $175 million in aggregate principal amount of the 2016 Notes are outstanding. This prospectus is being sent to DTC, the sole registered holder of the outstanding Notes, and to all persons that we can identify as beneficial owners of the outstanding Notes. There will be no fixed record date for determining registered holders of outstanding Notes entitled to participate in either exchange offer.

We intend to conduct each exchange offer in accordance with the provisions of the applicable registration rights agreement, the applicable requirements of the Securities Act and the Securities Exchange Act of 1934 and the rules and regulations of the SEC. Outstanding Notes that the holders thereof do not tender for exchange in the applicable exchange offer will remain outstanding and continue to accrue interest. These outstanding Notes will be entitled to the rights and benefits such holders have under the respective indenture relating to the Notes and the applicable registration rights agreement.

We will be deemed to have accepted for exchange properly tendered outstanding Notes when we have given oral or written notice of the acceptance to the exchange agent and complied with the applicable provisions of the registration rights agreement. The exchange agent will act as agent for the tendering holders for the purposes of receiving the new notes from us.

If you tender outstanding Notes in an exchange offer, you will not be required to pay brokerage commissions or fees or, subject to the letter of transmittal, transfer taxes with respect to the exchange of outstanding Notes. We will pay all charges and expenses, other than certain applicable taxes described below, in connection with each exchange offer. It is important that you read the section labeled " Fees and Expenses" for more details regarding fees and expenses incurred in an exchange offer.

We will return any outstanding Notes that we do not accept for exchange for any reason without expense to their tendering holder as promptly as practicable after the expiration or termination of the applicable exchange offer.

Expiration Date

Each exchange offer will expire at 5:00 p.m. New York City time on   , 200 , unless, in our sole discretion, we extend it. We may extend one exchange offer without extending the other.

Extensions, Delays in Acceptance, Termination or Amendment

We expressly reserve the right, at any time or various times, to extend the period of time during which either exchange offer is open. During any such extensions, all outstanding Notes previously tendered will remain subject to the applicable exchange offer, and we may accept them for exchange.

In order to extend an exchange offer, we will notify the exchange agent orally or in writing of any extension. We will notify the registered holders of outstanding Notes of the extension no later than 9:00 a.m., New York City time, on the business day after the previously scheduled expiration date.

If any of the conditions described below under "   Conditions to the Exchange Offers" have not been satisfied, in relation to either exchange offer, we reserve the right, in our sole discretion

to delay accepting for exchange any outstanding Notes,

to extend the exchange offer, or

to terminate the exchange offer,

by giving oral or written notice of such delay, extension or termination to the exchange agent. Subject to the terms of the applicable registration rights agreement, we also reserve the right to amend the terms of either exchange offer in any manner.

Any such delay in acceptance, extension, termination or amendment will be followed as promptly as practicable by oral or written notice thereof to the registered holders of outstanding Notes. If we amend an exchange offer in a manner that we determine to constitute a material change, we will promptly disclose such amendment by means of a prospectus supplement. The supplement will be distributed to the registered holders of the outstanding Notes that are subject to the applicable exchange offer. Depending upon the significance of the amendment and the manner of disclosure to the registered holders, we will extend such exchange offer if such exchange offer would otherwise expire during such period. If an amendment constitutes a material change to an exchange offer, including the waiver of a material condition, we will extend the applicable exchange offer, if necessary, to remain open for at least five business days after the date of the amendment. In the event of any increase or decrease in the price of the outstanding Notes or in the percentage of outstanding Notes being sought by us, we will extend the applicable exchange offer to remain open for at least 10 business days after the date we provide notice of such increase or decrease to the registered holders of outstanding Notes.

Conditions to the Exchange Offers

We will not be required to accept for exchange, or exchange any new Notes for, any outstanding Notes if the applicable exchange offer, or the making of any exchange by a holder of outstanding Notes, would violate applicable law or any applicable interpretation of the staff of the SEC. Similarly, we may terminate either exchange offer as provided in this prospectus before accepting outstanding Notes for exchange in the event of such a potential violation.

In addition, we will not be obligated to accept for exchange the outstanding Notes of any holder that has not made to us the representations described under "   Purpose and Effect of the Exchange Offers," "   Procedures for Tendering" and "Plan of Distribution" and such other representations as may be reasonably necessary under applicable SEC rules, regulations or interpretations to allow us to use an appropriate form to register the new Notes under the Securities Act.

We will not accept for exchange any outstanding Notes tendered, and will not issue new Notes in exchange for any such outstanding Notes, if at such time any stop order has been threatened or is in effect with respect to (1) the registration statement of which this prospectus constitutes a part or (2) the qualification of the applicable indenture relating to the Notes under the Trust Indenture Act of 1939.

We expressly reserve the right to amend or terminate either exchange offer, and to reject for exchange any outstanding Notes not previously accepted for exchange, upon the occurrence of any of the conditions to the exchange offers specified above. We will give oral or written notice of any extension, amendment, non-acceptance or termination to the holders of the outstanding Notes as promptly as practicable.

These conditions are for our sole benefit, and we may assert them or waive them in whole or in part at any time or at various times in our sole discretion. If we fail at any time to exercise any of these rights, this failure will not mean that we have waived our rights. Each such right will be deemed an ongoing right that we may assert at any time or at various times.

Each exchange offer is independent of the other, and the closing of one exchange offer is not conditioned upon the closing of the other.

Procedures for Tendering

In order to participate in an exchange offer, you must properly tender your outstanding Notes to the exchange agent as described below. It is your responsibility to properly tender your Notes. We have the right to waive any defects. However, we are not required to waive defects and are not required to notify you of defects in your tender.

If you have any questions or need help in exchanging your Notes, please call the exchange agent, whose address and phone number are set forth in "Prospectus Summary The Exchange Offers Exchange Agent."

All of the outstanding Notes were issued in book-entry form, and all of the outstanding Notes are currently represented by global certificates held for the account of DTC. We have confirmed with DTC that the outstanding Notes may be tendered using the Automated Tender Offer Program ("ATOP") instituted by DTC. The exchange agent will establish an account with DTC for purposes of the exchange offers promptly after the commencement of the exchange offers and DTC participants may electronically transmit their acceptance of the exchange offer by causing DTC to transfer their outstanding Notes to the exchange agent using the ATOP procedures. In connection with the transfer, DTC will send an "agent's message" to the exchange agent. The agent's message will state that DTC has received instructions from the participant to tender outstanding Notes and that the participant agrees to be bound by the terms of the applicable letter of transmittal.

By using the ATOP procedures to exchange outstanding Notes, you will not be required to deliver a letter of transmittal to the exchange agent. However, you will be bound by its terms just as if you had signed it.

There is no procedure for guaranteed late delivery of the outstanding Notes.

Determinations Under the Exchange Offers

We will determine in our sole discretion all questions as to the validity, form, eligibility, time of receipt, acceptance of tendered outstanding Notes and withdrawal of tendered outstanding Notes. Our determination will be final and binding. We reserve the absolute right to reject any outstanding Notes not properly tendered or any outstanding Notes our acceptance of which would, in the opinion of our counsel, be unlawful. We also reserve the right to waive any defect, irregularities or conditions of tender as to particular outstanding Notes. Our interpretation of the terms and conditions of either exchange offer, including the instructions in the applicable letter of transmittal, will be final and binding on all parties. Unless waived, all defects or irregularities in connection with tenders of outstanding Notes must be cured within such time as we shall determine. Although we intend to notify holders of defects or irregularities with respect to tenders of outstanding Notes, neither we, the exchange agent nor any other person will incur any liability for failure to give such notification. Tenders of outstanding Notes will not be deemed made until such defects or irregularities have been cured or waived. Any outstanding Notes received by the exchange agent that are not properly tendered and as to which the defects or irregularities have not been cured or waived will be returned to the tendering holder, unless otherwise provided in the applicable letter of transmittal, as soon as practicable following the applicable expiration date.

When We Will Issue New Notes

In all cases, we will issue new Notes for outstanding Notes that we have accepted for exchange under an exchange offer only after the exchange agent timely receives:

- a book-entry confirmation of such outstanding Notes into the exchange agent's account at DTC; and
- a properly transmitted agent's message.

Return of Outstanding Notes Not Accepted or Exchanged

If we do not accept any tendered outstanding Notes for exchange or if outstanding Notes are submitted for a greater principal amount than the holder desires to exchange, the unaccepted or non-exchanged outstanding Notes will be returned without expense to their tendering holder. Such non-exchanged outstanding Notes will be credited to an account maintained with DTC. These actions will occur as promptly as practicable after the expiration or termination of the applicable exchange offer.

Your Representations to Us

By agreeing to be bound by the applicable letter of transmittal, you will represent to us that, among other things:

- any new Notes that you receive will be acquired in the ordinary course of your business;
- you have no arrangement or understanding with any person or entity to participate in the distribution of the new Notes;
- you are not engaged in and do not intend to engage in the distribution of the new Notes;
- if you are a broker-dealer that will receive new Notes for your own account in exchange for outstanding Notes, you acquired those notes as a result of market-making activities or other trading activities and you will deliver a prospectus, as required by law, in connection with any resale of such new Notes; and
- you are not our "affiliate," as defined in Rule 405 of the Securities Act.

Withdrawal of Tenders

Except as otherwise provided in this prospectus, you may withdraw your tender at any time prior to 5:00 p.m. New York City time on the expiration date. For a withdrawal to be effective you must comply with the appropriate procedures of DTC's ATOP system. Any notice of withdrawal must specify the name and number of the account at DTC to be credited with withdrawn outstanding Notes and otherwise comply with the procedures of DTC.

We will determine all questions as to the validity, form, eligibility and time of receipt of notice of withdrawal. Our determination shall be final and binding on all parties. We will deem any outstanding Notes so withdrawn not to have been validly tendered for exchange for purposes of the applicable exchange offer.

Any outstanding Notes that have been tendered for exchange but are not exchanged for any reason will be credited to an account maintained with DTC for the outstanding Notes. This return or crediting will take place as soon as practicable after withdrawal, rejection of tender or termination of the applicable exchange offer. You may retender properly withdrawn outstanding Notes by following the procedures described under " Procedures for Tendering" above at any time prior to 5:00 p.m., New York City time, on the applicable expiration date.

Fees and Expenses

We will bear the expenses of soliciting tenders with respect to each exchange offer. The principal solicitation is being made by mail; however, we may make additional solicitation by telegraph, telephone or in person by our officers and regular employees and those of our affiliates.

We have not retained any dealer manager in connection with the exchange offers and will not make any payments to broker-dealers or others soliciting acceptances of the exchange offers. We will, however, pay the exchange agent reasonable and customary fees for its services and reimburse it for its related reasonable out of pocket expenses.

We will pay the cash expenses to be incurred in connection with each exchange offer. They include:

- SEC registration fees;
- fees and expenses of the exchange agent and trustee;
- accounting and legal fees and printing costs; and
- related fees and expenses.

Transfer Taxes

We will pay all transfer taxes, if any, applicable to the exchange of outstanding Notes under each exchange offer. The tendering holder, however, will be required to pay any transfer taxes, whether imposed on the registered holder or any other person, if a transfer tax is imposed for any reason other than the exchange of outstanding Notes under the applicable exchange offer.

Consequences of Failure to Exchange

If you do not exchange new Notes for your outstanding Notes under the applicable exchange offer, you will remain subject to the existing restrictions on transfer of the outstanding Notes. In general, you may not offer or sell the outstanding Notes unless they are registered under the Securities Act, or if the offer or sale is exempt from the registration under the Securities Act and applicable state securities laws. Except as required by the registration rights agreements, we do not intend to register resales of the outstanding Notes under the Securities Act.

Accounting Treatment

We will record the new Notes in our accounting records at the same carrying value as the outstanding Notes of the same series. This carrying value is the aggregate principal amount of the outstanding Notes less any bond discount, as reflected in our accounting records on the date of exchange. Accordingly, we will not recognize any gain or loss for accounting purposes in connection with either exchange offer.

Other

Participation in an exchange offer is voluntary, and you should carefully consider whether to accept. You are urged to consult your financial and tax advisors in making your own decision on what action to take.

We may in the future seek to acquire untendered outstanding Notes in open market or privately negotiated transactions, through subsequent exchange offers or otherwise. We have no present plans to acquire any outstanding Notes that are not tendered in the exchange offers or to file a registration statement to permit resales of any untendered outstanding Notes.

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 nine months ended September 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.

	Nine Months Ended September 30,		Year Ended December 31,				
	2004	2003	2003	2002	2001	2000	1999
	(in millions except per unit data)						
Statement of operations data:							
Revenues	$ 14,803.4	$ 9,044.8	$ 12,589.8	$ 8,384.2	$ 6,868.2	$ 6,641.2	$ 10,910.4
Cost of sales and field operations (excluding LTIP charge)	14,558.3	8,879.9	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 operations[1]	0.6	1.4	5.7				
General and administrative expenses (excluding LTIP charge)	54.6	37.4	50.0	45.7	46.6	40.8	23.2
LTIP charge general and administrative[1]	3.7	6.0	23.1				
Depreciation and amortization	45.9	34.2	46.8	34.0	24.3	24.5	17.3
Restructuring expense							1.4
Total costs and expenses	14,663.1	8,958.9	12,492.3	8,289.6	6,796.8	6,578.8	11,008.4
Gain on sale of assets	0.6	0.6	0.6		1.0	48.2	16.4
Operating income	140.9	86.5	98.2	94.6	72.4	110.6	(81.6)
Interest expense	(32.2)	(26.5)	(35.2)	(29.1)	(29.1)	(28.7)	(21.1)
Interest income and other, net[2]	(0.3)	(0.4)	(3.6)	(0.2)	0.4	(4.4)	(0.6)
Income (loss) from continuing operations before cumulative effect of change in accounting principle[12]	$ 108.4	$ 59.6	$ 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]	$ 1.63	$ 1.06	$ 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]	$ 1.63	$ 1.05	$ 1.00	$ 1.34	$ 1.12	$ 2.13	$ (3.21)
Basic weighted average number of limited partner units outstanding	61.9	51.7	52.7	45.5	37.5	34.4	31.6
Diluted weighted average number of limited partner units outstanding	61.9	52.4	53.4	45.5	37.5	34.4	31.6
Balance sheet data (at end of period):							
Total assets	$ 3,106.0	$ 1,810.1	$ 2,095.6	$ 1,666.6	$ 1,261.2	$ 885.8	$ 1,223.0
Total long-term debt[3][4]	837.6	453.7	519.0	509.7	354.7	320.0	424.1
Total debt[4]	960.5	488.9	646.2	609.0	456.2	321.3	482.8
Partners' capital	1,044.4	705.4	746.7	511.6	402.8	214.0	193.0
Other data:							
Maintenance capital expenditures	$ 6.1	$ 5.5	$ 7.6	$ 6.0	$ 3.4	$ 1.8	$ 1.7
Net cash provided by (used in) operating activities[5]	113.1	236.1	115.3	185.0	(16.2)	(33.5)	(71.2)
Net cash provided by (used in) investing activities[5]	(567.3)	(185.2)	(272.1)	(374.9)	(263.2)	211.0	(186.1)
Net cash provided by (used in) financing activities	453.4	(51.0)	157.2	189.5	279.5	(227.8)	305.6
Declared distributions per limited partner unit[6][7][8]	1.70	1.64	2.19	2.11	1.95	1.83	1.59

Table continued on following page.

	Nine Months Ended September 30,		Year Ended December 31,				
	2004	2003	2003	2002	2001	2000	1999
Operating Data:							
Volumes (thousands of barrels per day)[9]							
Pipeline segment:							
Tariff activities							
All American	55	60	59	65	69	74	103
Link acquisition	248	N/A	N/A	N/A	N/A	N/A	N/A
Capline	115	N/A	N/A	N/A	N/A	N/A	N/A
Basin	275	264	263	93	N/A	N/A	N/A
Other domestic[10]	420	283	299	219	144	130	61
Canada	257	191	203	187	132	N/A	N/A
Pipeline margin activities	72	80	78	73	61	60	54
Total	1,442	878	902	637	406	264	218
Gathering, marketing, terminalling and storage segment:							
Crude oil lease gathering	576	430	437	410	348	262	265
Crude oil bulk purchases[11]	143	84	90	68	46	28	138
Total	719	514	527	478	394	290	403
LPG sales	39	31	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 our adoption of Statement of Financial Accounting Standards ("SFAS") 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections" in January 2003, such items are now shown as impacting income from continuing operations. As a result of this reclassification, basic and diluted net income (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 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 $8.0 million, $9.0 million, $3.0 million, and $50.7 million at September 30, 2003, and 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 as of 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 December 31, 2003 "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) 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 liquified 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 September 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 2.5 million barrels per day of physical crude oil through our extensive network of assets located in major oil producing regions of the United States and Canada. Our operations consist of two operating segments: (i) pipeline operations ("Pipeline Operations") and (ii) gathering, marketing, terminalling and storage operations ("GMT&S"). Through our pipeline segment, we engage in interstate and intrastate crude oil pipeline transportation and certain related margin activities. Through our GMT&S segment, we engage in purchases and resales of crude oil and LPG at various points along the distribution chain and we operate certain terminalling and storage assets. Please read "Business Recent Developments" for more details regarding our recent acquisitions.

Overview of Operating Results and Significant Activities

Nine Months Ended September 30, 2004. During the first nine months of 2004, we recognized net income and earnings per limited partner unit of $105.3 million and $1.58, respectively, both of which were substantial increases over the first nine months of 2003. The results for the first nine months of 2004 as compared to the first nine months of 2003 include significant contributions from acquisitions completed during the second half of 2003 and during 2004.

We had the following significant activities during the first nine months of 2004:

- We consummated several acquisitions aggregating approximately $544 million. For a description of these acquisitions, please read " Acquisitions 2004 Acquisitions" and " Liquidity and Capital Resources."

- Despite significant acquisitions, we maintained the relative strength of our overall capital structure and maintained substantial liquidity through changes in our credit facilities, a series of equity issuances and senior notes issuances. During the nine month period, we expanded our secured hedged inventory facility. In addition, we raised approximately $262 million of equity capital in two separate transactions (including our general partner's proportionate capital contributions and net of costs associated with the offerings) and we accessed the debt capital markets by issuing an aggregate $350 million of five-year and twelve-year senior notes ($175 million tranche each) at effective yields of 4.75 percent and 5.88 percent, respectively.

- We changed our method of accounting for pipeline linefill in third party assets resulting in a cumulative effect of change in accounting principle of a charge of $3.1 million in the 2004 nine- month period. 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 nine months ended September 30, 2004.

- Recognized a foreign exchange gain of $3.4 million related to the impact of changes in the Canadian dollar to U.S. dollar exchange rate on a net U.S. dollar denominated liability in our Canadian subsidiary. This is primarily attributable to our LPG business, a substantial amount of which is transacted in U.S. Dollars.

- Recognized a non-cash gain of approximately $1.4 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 nine months of 2003 includes a non-cash loss of approximately $1.7 million.

- In July 2004, Standard & Poor's removed us from credit watch with negative implications and affirmed their BBB- stable senior unsecured rating (an investment grade rating). In September 2004, Moody's Investors Service completed their review and upgraded our senior unsecured rating to Baa3 with a stable outlook (an investment grade rating). You should note that a credit rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time.

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 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 acquisition 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.

Acquisitions

We completed several 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

In the first nine months of 2004, we completed several acquisitions for aggregate consideration of approximately $544.1 million. The aggregate consideration includes cash paid, estimated transaction costs and assumed liabilities and net working capital items. The following table summarizes our 2004 acquisitions, and a description of each of these follows the table:

Acquisition	Effective Date	Acquisition Price	Operating Segment
		(in millions)	
Capline and Capwood Pipeline Systems	03/01/04	$ 158.5	Pipeline
Link Energy LLC	04/01/04	332.1	Pipeline/GMT&S
Cal Ven Pipeline System	05/01/04	19.0	Pipeline
Schaefferstown Propane Storage Facility	08/25/04	32.0	GMT&S
Other[(1)]		2.5	
Total 2004 Acquisitions through September 30, 2004		$ 544.1	

(1) Includes 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. In December 2003, subsequent to the announcement of the acquisition and in anticipation of closing, we issued approximately 2.8 million common units for net proceeds of approximately $88.4 million, after paying approximately $4.1 million of transaction costs. The proceeds from this issuance were used to pay down our revolving credit facility. At closing, the cash portion of this acquisition was funded from cash on hand and borrowings under our revolving credit facility.

The principal assets of 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 $332 million, including $268 million of cash (net of approximately $5.5 million subsequently returned to us from an indemnity escrow account) and approximately $64 million of net liabilities assumed and acquisition related costs. The Link crude oil business consists of approximately 7,000 miles of active crude oil pipeline and gathering systems, over 10 million barrels of 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	$ 262.3
Inventory	1.1
Linefill	48.4
Inventory in third party assets	15.1
Goodwill	5.0
Other long term assets	0.2
Subtotal	332.1
Accounts receivable[1]	405.4
Other current assets	1.8
Subtotal	407.2
Total assets acquired	739.3
Fair value of liabilities assumed:	
Accounts payable and accrued liabilities[1]	(455.4)
Other current liabilities	(8.5)
Other long-term liabilities	(7.4)
Total liabilities assumed	(471.3)
Cash paid for acquisition[2]	$ 268.0

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

(2) 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 and related allocation; thus, the purchase price and allocation are both subject to refinement.

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

Cal Ven Pipeline System. On May 7, 2004 we completed the acquisition of the Cal Ven Pipeline System from Cal Ven Limited, a subsidiary of Unocal Canada Limited. The total purchase price was approximately $19 million, including transaction costs. The transaction was funded through a combination of cash on hand and borrowings under our revolving credit facilities. The Cal Ven Pipeline System includes approximately 195 miles of 8-inch and 10-inch gathering and mainline crude oil pipelines. The system is located in northern Alberta and delivers crude oil into the Rainbow Pipeline System. The Rainbow Pipeline System then transports the crude south to the Edmonton market, where it can be used in local refineries or shipped on connecting pipelines to the U.S. market. The results of operations and assets from this acquisition have been included in our consolidated financial statements and our pipeline operations segment since May 1, 2004.

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

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:

Acquisition	Effective Date	Acquisition Price	Operating Segment
		(in millions)	
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. The Rancho Pipeline System was taken out of service in March 2003, pursuant to the operating agreement. See "Business Acquisitions and Dispositions Shutdown and Sale of Rancho Pipeline System."

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

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 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
Total	$ 73.9

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.

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
Total	$	158.4

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 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:

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

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

Change in Accounting Principle

During the second quarter of 2004, we changed our method of accounting for pipeline linefill in third party assets. Historically, we have viewed pipeline linefill, whether in our assets or third party assets, as having long-term characteristics rather than characteristics typically associated with the short-term classification of operating inventory. Therefore, previously we have not included linefill barrels in the same average costing calculation as our operating inventory, but instead have carried linefill at historical cost. Following this change in accounting principle, the linefill in third party assets that we have historically classified as a portion of "Pipeline Linefill" on the face of the balance sheet (a long-term asset) and carried at historical cost, is included in "Inventory" (a current asset) in determining the average cost of operating inventory and applying the lower of cost or market analysis. At the end of each period, we 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 our consolidated statement of operations for the nine months ended September 30, 2004 and our consolidated balance sheet as of September 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 first nine months of 2003 would have been an increase to net income of approximately $2.2 million ($0.04 per basic and diluted limited partner unit) resulting in pro forma net income of $61.8 million and pro forma basic net income per limited partner unit of $1.10 and pro forma diluted net income per limited partner unit of $1.09.

In conjunction with this change in accounting principle, we have classified cash flows associated with purchases and sales of linefill on assets that we own as cash flows from investing activities instead of the historical classification of cash flows from operating activities. Accordingly, our statement of cash flows for the nine months ended September 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 $40.4 million for the nine months ended September 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 believe that the combination of our terminalling and storage activities and gathering and marketing activities provides a counter-cyclical balance that has a stabilizing effect on our results of operations and cash flow. In a contango market (oil prices for future deliveries are higher than for current deliveries), we use our tankage to improve our gathering margins by storing crude oil we have purchased at lower prices in the current month for delivery at higher prices in future months. In a backwardated market (oil prices for future deliveries are lower than for current deliveries), we use and lease less storage capacity, but increased marketing margins (premiums for prompt delivery) provide an offset to this reduced cash flow.

We evaluate segment performance based on segment profit and maintenance capital. We define segment profit as revenues less (i) purchases, (ii) field operating costs and (iii) segment general and administrative ("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 September 30, 2004 and December 31, 2003, we owned approximately 15,000 miles (of which approximately 13,100 miles are included in our pipeline segment) 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

As of September 30, 2004, and December 31, 2003, respectively, we owned approximately 37 million barrels (of which approximately 13.6 million barrels of capacity are used in our GMT&S segment) and 23.4 million 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 13.6 million barrels of our 37 million barrels of tankage is used primarily in our GMT&S Operations segment and the balance is used in our Pipeline Operations segment. On a stand-alone basis, segment profit from terminalling and storage activities is dependent on the throughput of volumes, the volume of crude oil stored and the level of fees generated from our terminalling and storage services. Our terminalling and storage activities are integrated with our gathering and marketing activities and the level of tankage that we allocate for our arbitrage activities (and therefore not available for lease to third parties) varies throughout crude oil price cycles. This integration enables us to use our storage tanks in an effort to counter-cyclically balance and hedge our gathering and marketing activities. In a contango market (when oil prices for future deliveries are higher than for current deliveries), we use our tankage to improve our gathering margins by storing crude oil we have purchased at lower prices in the current month for delivery at higher prices in future months. In a backwardated market (when oil prices for future deliveries are lower than for current deliveries), we use 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.

Our revenues from gathering and marketing activities reflect the sale of gathered and bulk-purchased crude oil and LPG volumes, plus the sale of additional barrels exchanged through buy/sell arrangements entered into to supplement the margins of the gathered and bulk-purchased volumes. Because the commodities that we buy and sell are generally indexed to the same pricing indices for both the purchase and the sale, revenues and costs related to purchases will increase and decrease with changes in market prices. However, the margins related to those purchases and sales will not necessarily have corresponding increases and decreases. For example, our revenues increased approximately 66% in the first nine months of 2004 compared to the first nine months of 2003, while our segment profit increased almost 30% in the same period.

Revenues from our GMT&S operations were approximately $14.2 billion and $8.6 billion for the nine months ended September 30, 2004 and 2003, respectively. Revenues and costs related to purchases for the 2004 period were impacted by higher average prices and higher volumes as compared to the 2003 period. Approximately 52% of the increase in revenues resulted from higher average prices in the 2004 period and the remainder was attributable to increased sales volumes. The average NYMEX price for crude oil was $39.09 per barrel and $31.03 per barrel for the nine months ended September 30, 2004 and 2003, respectively.

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

Nine Months Ended September 30, 2004 and 2003

For the nine months ended September 30, 2004, we reported consolidated net income of $105.3 million on total revenues of $14.8 billion compared to net income for the same period in 2003 of $59.6 million on total revenues of $9.0 billion. 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)	
Nine Months Ended September 30, 2004[(1)]		
Revenues	$ 639.5	$ 14,247.6
Purchases	(408.4)	(14,075.8)
Field operating costs (excluding LTIP charge)	(84.8)	(73.3)
LTIP charge operations	(0.1)	(0.4)
Segment G&A expenses (excluding LTIP charge)[(2)]	(27.3)	(27.2)
LTIP charge general and administrative	(1.7)	(2.0)
Segment profit	$ 117.2	$ 68.9
Noncash SFAS 133 impact[(3)]	$	$ 1.4
Maintenance capital	$ 4.1	$ 2.0
Nine Months Ended September 30, 2003[(1)]		
Revenues	$ 489.1	$ 8,594.8
Purchases	(362.9)	(8,457.2)
Field operating costs (excluding LTIP charge)	(42.3)	(56.6)
LTIP charge operations	(0.4)	(1.0)
Segment G&A expenses (excluding LTIP charge)[(2)]	(13.7)	(23.7)
LTIP charge general and administrative	(2.6)	(3.4)
Segment profit	$ 67.2	$ 52.9
Noncash SFAS 133 impact[(3)]	$	$ (1.7)
Maintenance capital	$ 4.8	$ 0.7

(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.

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

	Nine Months Ended September 30,	
	2004	2003
Operating Results(1) (in millions)		
Revenues		
Tariff activities	$ 215.3	$ 112.4
Pipeline margin activities	424.2	376.7
Total pipeline operations revenues	639.5	489.1
Costs and Expenses		
Pipeline margin activities purchases	(408.4)	(362.9)
Field operating costs (excluding LTIP charge)	(84.8)	(42.3)
LTIP charge operations	(0.1)	(0.4)
Segment G&A expenses (excluding LTIP charge)(2)	(27.3)	(13.7)
LTIP charge general and administrative	(1.7)	(2.6)
Segment profit	$ 117.2	$ 67.2
Maintenance capital	$ 4.1	$ 4.8
Average Daily Volumes(3) (thousands of barrels per day)		
Tariff activities		
All American	55	60
Basin	275	264
Link acquisition	248	N/A
Capline	115	N/A
Other domestic	420	283
Canada	257	191
Total tariff activities	1,370	798
Pipeline margin activities	72	80
Total	1,442	878

(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 revenues from our pipeline operations were approximately $639.5 million and $489.1 million for the nine months ended September 30, 2004 and 2003, respectively. An increase in revenues from tariff activities accounted for $102.9 million of the increase (see discussion below). Additionally, revenues from our margin activities increased by approximately $47.5 million in the 2004 period. 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. As mentioned above, 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 (i) the first quarter of

2003 including additional shipments that typically move on other pipelines and (ii) the use by refineries of foreign crude oil instead of crude oil transported on the SJV system.

Segment profit, our primary measure of segment performance, increased approximately 74% to $117.2 million for the nine months ended September 30, 2004 as compared to the 2003 period. The primary drivers impacting the 2004 period as compared to the 2003 period are:

Increased volumes and related tariff revenues The increase in volumes and related tariff revenues is primarily related to the Link acquisition and other acquisitions completed during 2004 and late 2003.

Higher realized prices on our loss allowance oil Higher crude oil prices during 2004 as compared to 2003 have resulted in increased revenues related to loss allowance oil.

Increased field operating costs Our continued growth, primarily from the Link acquisition and other acquisitions completed during 2004 and late 2003 is the principal driver of the increase in field operating costs of $42.2 million to $84.9 million for the third quarter of 2004. The increased costs are primarily in payroll and benefits and utilities. In addition, costs related to our pipeline integrity management program have increased in 2004.

Increased segment G&A expenses Segment G&A expenses have increased approximately $12.7 million to $29.0 million in the third quarter of 2004 from the third quarter of 2003. The increase in the current quarter is primarily related to the Link acquisition coupled with the percentage of indirect costs allocated to the pipeline operations segment continuing to increase in the 2004 period as our pipeline operations have grown. G&A costs have also increased because of increased headcount from our continued growth and higher costs related to Sarbanes-Oxley requirements. These items were partially offset by the inclusion of an LTIP charge of approximately $2.6 million in the 2003 period.

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

	Nine Months Ended September 30,			
	2004		2003	
	Volumes	Revenues	Volumes	Revenues
	(volumes in thousands of barrels per day and revenues in millions)			
Tariff activities[1][2]				
2004 acquisitions	471	$ 77.7		$
2003 acquisitions	168	27.7	58	8.0
All other pipeline systems	731	109.9	740	104.4
Total tariff activities	1,370	$ 215.3	798	$ 112.4

(1) Revenues include intersegment amounts.

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

Average daily volumes from our tariff activities increased 72% to approximately 1.4 million barrels per day and revenues from our tariff activities increased 92% to $215.3 million. The increase in the third quarter of 2004 is predominately related to (i) the inclusion of an average of 248,000 barrels per day and $52.7 million of revenues from the pipelines acquired in the Link acquisition and (ii) 223,000 barrels per day and $25.0 million of revenues from other businesses acquired in 2004.

Volumes from pipeline systems acquired in 2003 have increased to an average of 168,000 barrels per day from an average of 58,000 barrels per day, while related revenues increased to $27.7 million from $8.0 million. The increase is primarily the result of the inclusion of several pipeline systems in the 2004 period that were acquired during or after 2003 (See "Acquisitions"), coupled with higher realized prices on our loss allowance oil. Volumes and revenues from all other pipeline systems were relatively flat between years.

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

	Nine Months Ended September 30,	
	2004	2003
Operating Results[1] (in millions)		
Revenues	$ 14,247.6	$ 8,594.8
Purchases and related costs	(14,075.8)	(8,457.2)
Field operating costs (excluding LTIP charge)	(73.3)	(56.6)
LTIP charge operations	(0.4)	(1.0)
Segment G&A expenses (excluding LTIP charge)[2]	(27.2)	(23.7)
LTIP charge general and administrative	(2.0)	(3.4)
Segment profit	$ 68.9	$ 52.9
Noncash SFAS 133 impact[3]	$ 1.4	$ (1.7)
Maintenance capital	$ 2.0	$ 0.7
Average Daily Volumes[4] (thousands of barrels per day)		
Crude oil lease gathering	576	430
Crude oil bulk purchases	143	84
Total	719	514
LPG sales[5]	39	31

(1) Revenues and purchases and related costs 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) Prior period volumes have been adjusted for consistency of comparison between years. Sales reflect only third party volumes.

Segment profit increased approximately 30% to $68.9 million for the first nine months of 2004 as compared to the first nine months of 2003. The primary drivers for the increase in the current year were:

Increased crude oil lease gathered volumes and LPG sales volumes The crude oil volumes gathered from producers, using our assets or third-party assets, has increased by approximately 34% to 576,000 barrels per day for the first nine months of 2004. The increase is primarily related to the Link acquisition, which has offset natural production declines. In addition, we marketed 39,000 barrels per day of LPG during the current period compared to 31,000 barrels per day in 2003.

Favorable market conditions During the first nine months of 2004, market conditions were favorable as the market was relatively volatile, with periods of strong backwardation as well as a short-lived contango structure. The NYMEX benchmark price of crude ranged from $32.20 to $50.20 during the period. This volatile market allowed us to optimize and enhance the margins of both our gathering and marketing assets and our terminalling and storage assets at different times during the period. The market conditions in the first nine months of 2003 were also favorable as there was relatively high volatility and strong backwardation throughout the period. During the first nine months of 2003, the NYMEX benchmark price of crude ranged from $25.04 to $39.99.

Change in impact from the SFAS 133 mark-to-market adjustment The first nine months of 2004 included a non-cash gain of approximately $1.4 million resulting from the mark-to-market of open derivative instruments pursuant to SFAS 133, while the first nine months of 2003 included a non-cash loss of approximately $1.7 million.

Impact of change in Canadian dollar to U.S. dollar exchange rate The 2004 period includes a foreign exchange gain of $3.4 million. The gain is related to the impact of changes in the Canadian dollar to U.S. dollar exchange rate on a net U.S. dollar denominated liability in our Canadian subsidiary. This is primarily attributable to our LPG business, a substantial amount of which is transacted in US Dollars.

Increased field operating costs Field operating costs increased to approximately $73.7 million in the current period from $57.6 million in the 2003 period primarily related to the Link acquisition. This increase was partially offset by the $1 million charge related to our LTIP in the 2003 period compared to $0.4 million in the 2004 period.

Increased segment G&A expenses G&A expense was approximately $2.1 million higher in the 2004 period than in the 2003 period. The increase is primarily related to increased headcount resulting from continued growth and higher costs related to Sarbanes-Oxley requirements partially offset by a decrease in the percentage of indirect costs allocated to the GMT&S operations segment as the growth in our pipeline operations segment has outpaced growth in our GMT&S operations segment. The increase is partially offset by the $3.4 million charge related to our LTIP in the 2003 period compared to $2.0 million in the 2004 period.

The impact of the items discussed above resulted in segment profit per barrel (calculated based on our lease gathered crude oil and LPG barrels) of $0.41 per barrel for the nine months ended September 30, 2004, compared to $0.42 for the nine months ended September 30, 2003.

Other Expenses

Depreciation and Amortization. Depreciation and amortization expense was $45.9 million for the nine months ended September 30, 2004, compared to $34.2 million for the nine months ended September 30, 2003. The increase relates primarily to the assets from our 2004 acquisitions and our various 2003 acquisitions being included for the full nine months in 2004 versus only a part or none of the nine months in 2003. Additionally, several capital projects were completed during late 2003 that were not included in the first nine months of 2003 depreciation expense. Amortization of debt issue costs was $1.9 million and $3.0 million in the first nine months of 2004 and 2003, respectively.

Interest Expense. During the first nine months of 2004, our average debt balance was approximately $719 million. This balance consisted of fixed rate senior notes averaging $514 million and borrowings under our revolving credit facilities averaging $205 million. During the comparable 2003 period, our average debt balance was approximately $525 million and consisted of fixed rate senior notes with a face amount of $200 million and borrowings under our revolving credit facilities of $325 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. Our financial growth strategy is to fund our acquisitions using a balance of debt and equity.

The changes to our debt structure and our interest rate hedging instruments mentioned above resulted in an increase in the average amount of fixed rate debt outstanding in the first nine months of 2004 to approximately 72% as compared to approximately 38% in the first nine months of 2003. In addition, during these two periods the average three-month LIBOR rate rose to 1.4% in 2004 from 1.1% in 2003.

The net impact of the items discussed above was an increase in interest expense for the nine months ended 2004 of approximately $5.7 million to a total of $32.2 million. The higher average debt balance in the 2004 period resulted in additional interest expense of approximately $8.3 million, while at the same time our commitment and other fees decreased by approximately $1.6 million. Our weighted average interest rate, excluding commitment and other fees, was approximately 5.7% for the nine months ended 2004 compared to 6.0% for the nine months ended 2003. The lower weighted average rate decreased interest expense by approximately $1.0 million during the nine months ended 2004 compared to the nine months ended 2003.

Other. During the third quarter of 2004, we completed the issuance of 4,968,000 common units and the outstanding Notes. We used the proceeds from these issuances to, among other things, repay amounts outstanding under our revolving credit facilities, including all amounts outstanding under the $200 million, 364-day facility we used to fund the Link acquisition. The repayment and termination of this facility resulted in a non-cash charge of approximately $0.7 million associated with the write-off of unamortized debt issue costs.

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) 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.

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[1] (in millions)			
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[3][4] (thousands of barrels per day)			
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.

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
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.

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

	December 31,		
	2003	2002	2001
Operating Results[1] (in millions)			
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[4] (thousands of barrels per day)			
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.

Revenues increased approximately 51% in 2003 compared to the prior year, while our segment profit increased 7% 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 2003. The increase in sales volumes primarily related to barrels sold under buy/sell and bulk purchase arrangements, both of which generate significantly less margin than our lease gathered barrels. We do not consider barrels sold under these arrangements to be a primary driver of segment performance and they are not included in the volumes we disclose as lease gathered barrels, which are a primary driver of segment performance. Segment profits from these arrangements are generally lower and not as sustainable as our lease purchased barrels, as they are driven mainly by market opportunity, and can vary significantly from month to month. With respect to a relationship between volumes and segment profit, we expect our segment profit to increase or decrease directionally with increases or decreases in lease gathered volumes and LPG sales volumes.

As a result of completing our Phase II and III expansions at our Cushing facility, total Cushing tankage dedicated to our Gathering, Marketing, Terminalling and Storage Operations was approximately 1.5 million barrels greater in 2003 relative to 2002. A portion of such tankage was employed in hedging activities related to our gathering and marketing activities in 2003 and the latter portion of 2002.

During 2003, market conditions were extremely volatile as a confluence of several events caused the NYMEX benchmark price of crude oil to fluctuate widely with prices ranging from as high as $39.99 per barrel to as low as $25.04 per barrel. For much of the first eight months of 2003, the crude oil market was in steep backwardation. Although the crude oil market was characterized by high absolute prices in the fourth quarter, the average backwardation for the quarter was in line with a normal crude oil market. These market conditions and volatility, in conjunction with our hedging strategies, enhanced the returns of our gathering and marketing activities. This was partially offset by the negative impact that the August 2003 blackout had on our fourth quarter margins. In contrast, market conditions during 2002 were less favorable as the crude oil market alternated between periods of weak contango and strong backwardation. In 2001, the market alternated between weak contango and weak backwardation.

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;
- 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).

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

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

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

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

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

Sarbanes Oxley Act and 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 recurrence of similar 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 September 30, 2004, we had a working capital deficit of approximately $50.5 million, approximately $401.1 million of availability under our committed revolving credit facilities and $240.5 million of unused capacity under our uncommitted hedged inventory facility. Usage of the credit facilities is subject to compliance with covenants. We believe we are currently in compliance with all covenants.

In the third quarter of 2004, we completed a public offering of 4,968,000 common units for $33.25 per unit. The offering resulted in gross proceeds of approximately $165.2 million from the sale of units and approximately $3.4 million from our general partner's proportionate capital contribution. Total costs associated with the offering, including underwriter fees and other expenses, were approximately $7.7 million. Net proceeds of $160.9 million were used to permanently reduce outstanding borrowings under the $200 million, 364-day credit facility.

On August 12, 2004, we sold the outstanding Notes. 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.

In November 2004, we entered into a new $750 million, five-year senior credit facility, which contains a sub-facility for Canadian borrowings up to $300 million. The new facility extends our maturities, lowers our cost of credit and provides an additional $125 million of liquidity over our previous facility. The facility can be expanded to $1 billion. Also in November 2004, we increased the capacity of our uncommitted senior secured hedged inventory facility to $400 million (with the ability to increase in the future by an incremental $100 million), and extended the maturity to November 2005.

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 $139.4 million on expansion capital projects during 2004. This includes our original estimate of expansion capital, newly announced projects and expansion capital associated with the Link acquisition. Our 2004 expansion capital projects include the following notable projects with the estimated cost for the entire year.

	Incurred Through September 30, 2004	Estimated to be Incurred in the Fourth Quarter of 2004	2004 Total
		(in millions)	
Cushing to Caney pipeline project	$ 14.6	$ 27.4	$ 42.0
Trenton pipeline expansion	0.7	18.6	19.3
Capital projects and upgrades associated with the Link acquisition	4.8	4.2	9.0
Capital projects and upgrades associated with the Cal Ven acquisition		2.5	2.5
Cushing Phase IV expansion	10.0		10.0
Upgrade and expansion related to acquisitions made in 2003	8.2	0.9	9.1
Iatan System expansion	3.7		3.7
Other	25.6	18.2	43.8
	$ 67.6	$ 71.8	$ 139.4

In addition, we expect to spend approximately $10.1 million on maintenance capital projects during 2004. For the first nine months of 2004, we have incurred approximately $6.1 million on maintenance capital projects.

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 a corollary adverse effect on our borrowing capacity.

Cash Flows

Cash flows for the nine months ended September 30, 2004 and 2003 were as follows:

	Nine Months Ended September 30, 2004	2003
	(in millions)	
Cash provided by (used in):		
Operating activities	$ 113.1	$ 236.1
Investing activities	(567.3)	(185.2)
Financing activities	453.4	(51.0)

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 or in months that we increase linefill. The storage of crude oil in periods of a contango market can have a material impact on our cash flows from operating activities for the period we pay for and store the crude oil and the subsequent period that we receive proceeds from the sale of the crude oil. When we store 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 $113.1 million and $236.1 million in 2004 and 2003, respectively.

Investing Activities. Net cash used in investing activities in 2004 and 2003 consisted predominantly of cash paid for acquisitions. Net cash used in 2004 was $567.3 million and was primarily comprised of (i) $142.5 million paid for the Capline and Capwood Pipeline Systems acquisition (a deposit had been paid in December 2003) (ii) approximately $283 million paid for the Link acquisition, (iii) approximately $19 million paid for the CalVen acquisition (iv) approximately $46.2 million paid for the Schaefferstown acquisition (including inventory of $14.2 million) (v) approximately $63.6 million paid for additions to property and equipment, and (vi) approximately $10.2 million paid for linefill on assets that we own. Some of the major items included in cash paid for additions to property and equipment is (i) approximately $8.6 million related to the Cushing Phase IV expansion, (ii) approximately $5.0 million related to the Iatan System expansion, (iii) approximately $5.4 million of maintenance capital, (iv) approximately $10.7 million related to the Cushing to Caney pipeline project, and (v) approximately $6.6 million related to our Red River pipeline system. Net cash used in investing activities in 2003 includes approximately $99.9 million paid for acquisitions and approximately $52.2 million for additions to property and equipment. In addition, approximately $40.4 million was paid for linefill on assets that we own. We received proceeds from sales of assets of approximately $7.1 million.

Financing Activities. Cash provided by financing activities in 2004 was approximately $453.4 million and was comprised of (i) approximately $100.8 million of proceeds from the issuance of Class C common units, (ii) approximately $160.9 million of proceeds from the issuance of common units, (iii) approximately $346.4 million of proceeds from the sale of the outstanding Notes, (iv) net short and long-term borrowings under our revolving credit facility of approximately $4.7 million, (v) net repayments under our short-term letter of credit and hedged inventory facility of approximately $42.2 million resulting from the collection of receivables related to prior year sales of inventory that was stored because of contango market conditions and (vi) $114.5 million of distributions paid to common unitholders and the general partner. Cash used in financing activities in 2003 consisted of (i) approximately $161.9 million of proceeds from the issuance of common units used to pay down outstanding balances on the revolving credit facility and a secured term loan, (ii) $89.3 million of distributions paid to unitholders and the general partner, (iii) a $43.0 million of principal repayments of our term loans, (iv) net long-term repayments under our revolving credit facilities of $13.1 million, and (v) net short-term debt repayments of $67.3 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 September 30, 2004, we had received approximately $24.4 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. Commerce Department. In 2002, we determined that we may have exceeded our licenses with respect to the quantity of crude oil exported and the end-users in Canada. Export of crude oil except as authorized by license is a violation of the EAR. In October 2002, we submitted to the BIS an initial notification of voluntary disclosure. The BIS subsequently informed us that we could continue to export while previous exports were under review. We applied for and received several new licenses allowing for export volumes and end users that more accurately reflect our anticipated business and customer needs. We also conducted reviews of new and existing contracts and implemented new procedures and practices in order to monitor compliance with applicable laws regarding the export of crude oil to Canada. As a result, we subsequently submitted additional information to the BIS in October 2003 and May 2004. In August 2004, we received a request from the BIS for additional information. We have responded to this and subsequent requests, and continue to cooperate fully with BIS officials. At this time, we have received neither a warning letter nor a charging letter, which could involve the imposition of penalties, and no indication of what penalties the BIS might assess. As a result, we cannot reasonably estimate the ultimate impact of this matter.

Alfons Sperber v. Plains Resources Inc., et al. On December 18, 2003, a putative class action lawsuit was filed in the Delaware Chancery Court, New Castle County, entitled Alfons Sperber v. Plains Resources Inc., et al. This suit, brought on behalf of a putative class of Plains All American Pipeline, L.P. common unitholders, 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.

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

Environmental. We may experience future releases of crude oil into the environment from our pipeline, gathering and storage operations, or discover past releases that were previously unidentified. Although we maintain an inspection program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to any such environmental releases from our assets may substantially affect our business. At September 30, 2004, our reserve for environmental liabilities totaled approximately $21.4 million. Approximately $13.8 million of the reserve is related to liabilities assumed as part of the Link acquisition. Although we believe our reserve is adequate, no assurance can be given that any costs incurred in excess of this reserve would not have a material adverse effect on our financial condition, results of operations or cash flows.

Other. A pipeline, terminal or other facility may experience damage as a result of an accident or natural disaster. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance of various types that we consider adequate to cover our operations and properties. The insurance covers our assets in amounts considered reasonable. The insurance policies are subject to deductibles that we consider reasonable and not excessive. Our insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues. The 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, indemnified or reserved against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe we are adequately insured for public liability and property damage to others with respect to our operations. With respect to all of our coverage, no assurance can be given that we will be able to maintain adequate insurance in the future at rates we consider reasonable, or that we have established adequate reserves to the extent that such risks are not insured.

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 the outstanding Notes to which this exchange relates. We used the proceeds from the sale of the outstanding Notes to repay amounts outstanding under our credit facilities, including the remaining balance under the $200 million, 364-day facility funded in connection with the Link acquisition, and for general partnership purposes. In connection with this repayment, we terminated the facility. The repayment and termination of this facility resulted in a non-cash charge of approximately $0.7 million associated with the write-off of unamortized debt issue costs. Subsequent to the Notes offering, we also terminated our $125 million, 364-day facility that was scheduled to expire in November 2004.

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.

In November 2004, we entered into a new $750 million, five-year senior unsecured credit facility, which contains a sub-facility for Canadian borrowings of up to $300 million. The new credit facility extends our maturities, lowers our cost of credit and provides an additional $125 million of liquidity over our previous facilities. This facility can be expanded to $1 billion. As of November 30, 2004, we had approximately $195.5 million outstanding under this credit facility, as well as $58.7 million in letters of credit outstanding, resulting in unused capacity under the facility of approximately $495.8 million.

Also in November 2004, we amended and restated our secured hedged inventory facility; increasing the facility to $400 million, with the ability to further increase the facility in the future by an incremental $100 million. This facility is an uncommitted working capital facility, which is used to finance the purchase of hedged crude oil inventory for storage when market conditions warrant. Borrowings under the hedged inventory facility are secured by the inventory purchased under the facility and the associated accounts receivable, and will be repaid with the proceeds from the sale of such inventory. This facility expires in November 2005. As of November 30, 2004, we had approximately $124.8 million outstanding and no letters of credit issued under our hedged crude oil inventory facility resulting in unused uncommitted capacity under this facility of approximately $275.2 million.

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

- incur indebtedness if certain financial ratios are not maintained;
- grant liens;
- engage in transactions with affiliates;
- enter into sale-leaseback transactions;
- sell substantially all of our assets or enter into a merger or consolidation.

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

- an interest coverage ratio that is not less than 2.75 to 1.0; and
- a debt coverage ratio which will not be greater than 4.75 to 1.0 on all outstanding debt and 5.25 to 1.0 on all outstanding debt during an acquisition period (generally, the period consisting of three fiscal quarters following an acquisition greater than $50 million).

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

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

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 September 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	$	$	$ 0.4	$ 30.0	$	$ 810.0	$ 840.4
Operating leases[1]	4.1	15.9	13.9	10.3	5.7	13.1	63.0
Capital expenditure obligations	46.0	8.7					54.7
Other long-term liabilities	0.8	0.5	0.2				1.5
Total	$ 50.9	$ 25.1	$ 14.5	$ 40.3	$ 5.7	$ 823.1	$ 959.6

(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 third quarter 2004, these purchases averaged approximately $1.8 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 September 30, 2004, we had outstanding letters of credit of approximately $123.9 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 November 12, 2004, we paid a cash distribution of $0.60 per unit on all outstanding units. The total distribution paid was approximately $43.9 million, with approximately $40.4 million paid to our common unitholders and approximately $3.5 million paid to our general partner for its general partner ($0.8 million) and incentive distribution interests ($2.7 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 $4.9 million in incentive distributions to our general partner. Thus far in 2004 (through November 12, 2004), we have paid $8.3 million in incentive distributions to our general partner. See "Certain Relationships and Related Transactions Our General Partner."

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements as defined by Item 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 December 31, 2003 Consolidated Financial Statements for a discussion of the mitigation of credit risk). 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" of our December 31, 2003 Consolidated Financial Statements.

All of our open commodity price risk derivatives at September 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	$ 29.2	$ (15.5)
Swaps and options contracts	(16.0)	(1.2)
LPG:		
Futures contracts		
Swaps and option contracts	(2.6)	3.6

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 September 30, 2004. The 7.75% senior notes issued during 2002 and the 5.625% senior notes issued during 2003 and the outstanding Notes issued in 2004 are fixed rate notes and their interest rates are not subject to market risk. Our variable rate debt bears interest at LIBOR, prime or the bankers acceptance plus the applicable margin. The average interest rates presented below are based upon rates in effect at September 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	$ 122.9	$	$	$	$	$	$ 122.9
Average interest rate	2.7%						2.7%
Long-term debt variable rate	$	$	$ 0.4	$ 30.0	$	$ 10.0	$ 40.4
Average interest rate			6.5%	4.7%		2.8%	4.3%

Currency Exchange Rate Risk Hedging

Our cash flow stream relating to our Canadian operations is based on the U.S. dollar equivalent of such amounts measured in Canadian dollars. Assets and liabilities of our Canadian subsidiaries are translated to U.S. dollars using the applicable exchange rate as of the end of a reporting period. Revenues, expenses and cash flow are translated using the average exchange rate during the reporting period.

Because a significant portion of our Canadian business is conducted in Canadian dollars, we use certain financial instruments to minimize the risks of changes in the exchange rate. These instruments include forward exchange contracts and cross currency swaps. The forward exchange contracts qualify for hedge accounting as cash flow hedges and the cross currency swaps qualify for hedge accounting as fair value hedges, both in accordance with SFAS 133.

At September 30, 2004, we had forward exchange contracts that allow us to exchange Canadian dollars for U.S. dollars, quarterly, at set exchange rates as detailed below:

	Canadian Dollars	US Dollars	Rate
	($ in millions)		
2004	$ 5.0	$ 3.8	1.32 to 1
2005	$ 3.0	$ 2.3	1.33 to 1
2006	$ 2.0	$ 1.5	1.32 to 1

In addition, at September 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 Canadian dollar to U.S. dollar exchange rate of 1.55 to 1). The notional principal amount reduces by $2.0 million U.S. in May 2005 and has a final maturity in May 2006 ($19.0 million U.S.). At September 30, 2004, $6.2 million of our long-term debt was denominated in Canadian dollars ($7.8 million Canadian based on a Canadian dollar to U.S. dollar exchange rate of 1.26 to 1). All of these financial instruments are placed with what we believe to be large, creditworthy financial institutions.

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

	Year of Maturity				
	2004	2005	2006	2007	Total
Forward exchange contracts	$ (0.1)	$ (0.4)	$ (0.2)	$	$ (0.7)
Cross currency swaps	(0.1)	(0.8)	(4.1)		(5.0)
Total	$ (0.2)	$ (1.2)	$ (4.3)	$	$ (5.7)

BUSINESS

General

We are a publicly traded Delaware limited partnership, formed in 1998 and engaged in interstate and intrastate crude oil transportation, and crude oil gathering, marketing, terminalling and storage, as well as the marketing and storage of liquefied petroleum gas and natural gas related petroleum products. We refer to liquefied petroleum gas and 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 September 30, 2004, we owned approximately 15,000 miles of gathering and mainline crude oil pipelines located throughout the United States and Canada; of which approximately 13,100 miles are included in our pipeline segment. Our activities from pipeline operations generally consist of transporting crude oil for a fee, third party leases of pipeline capacity, barrel exchanges and buy/sell arrangements.

- *Gathering, Marketing, Terminalling and Storage Operations*. As of September 30, 2004, we owned approximately 37 million barrels of above ground crude oil terminalling and storage facilities, including approximately 23.4 million barrels of tankage that are associated with pipeline operations within our pipeline segment. These facilities include a crude oil terminalling and storage facility at Cushing, Oklahoma. Cushing, which we refer to in this report as the Cushing Interchange, is one of the largest crude oil market hubs in the United States and the designated delivery point for NYMEX crude oil futures contracts. We utilize our storage tanks to counter cyclically balance our gathering and marketing operations and to execute various hedging strategies to stabilize profits and reduce the negative impact of crude oil market volatility. Our terminalling and storage operations also generate revenue at the Cushing Interchange and our other locations through a combination of storage and throughput charges to third parties. We also own approximately 72 million gallons of LPG storage. 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. Since commencing LPG activities in mid-2001, 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 third quarter 2004 results, 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 outside the parameters of our targeted credit profile.

Credit Rating

As of November 30, 2004, our senior unsecured rating with Standard & Poors and Moody's Investment Services was BBB-stable and Baa3 stable, both of which are considered investment grade. We cannot assure you that these ratings will remain in effect for any given period of time or that one or both of these ratings will not be lowered or withdrawn entirely by a rating agency. 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. In many instances, 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. Since becoming operational in late 1993, we have completed four separate expansion phases, increasing the Cushing terminal's tankage to 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 November 30, 2004, we had approximately $495.8 million available under our committed 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 generally 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

Unitholder Meeting

On December 7, 2004, we filed a proxy statement to call a special meeting of our unitholders. At the meeting, our unitholders will consider and vote on the following matters:

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

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

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

Any proposal to adjourn the special meeting to a later date, if necessary, to solicit additional proxies if there are not sufficient votes in favor of the foregoing proposals.

Our board of directors unanimously recommended that the common unitholders approve the Class B Listing Proposal, the Class C Listing Proposal and the 2005 LTIP Proposal. Pursuant to our partnership agreement, if the approval of our common unitholders is not obtained within 120 days of the request, the holders of the Class B common units and the Class C common units (unless and until converted into common units) will be entitled to receive distributions, on a per unit basis, equal to 110% of the amount of distributions paid on a common unit. If the approval of our common unitholders is not secured within 90 days after the end of the 120-day period, the distribution right increases to 115%. If the approval of our common unitholders is not obtained for the 2005 LTIP Proposal, we will not be able to award any grants under the 2005 LTIP. See "Certain Relationships and Related Transactions Transactions with Related Parties Class B Common Units" and "Certain Relationships and Related Transactions Transactions with Related Parties Class C Common Units" for a discussion of the Class B and Class C common units.

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 Payment

On November 12, 2004, we paid a cash distribution of $0.60 per unit on our outstanding common units, Class B common units and Class C common units. The total distribution paid was approximately

$43.9 million, with approximately $40.4 million paid to our common unitholders and approximately $3.5 million paid to our general partner for its general partner ($0.8 million) and incentive distribution interests ($2.7 million).

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 $160.9 million. We used the net proceeds to pay down outstanding indebtedness and reduce the commitment level under our $200 million, 364-day credit facility.

Debt Offering

On August 12, 2004, we sold the outstanding Notes. 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.

Credit Facility

In November 2004, we entered into a new $750 million, five-year senior credit facility, which contains a sub-facility for Canadian borrowings up to $300 million. The new facility extends our maturities, lowers our cost of credit and provides an additional $125 million of liquidity over our previous facility. The facility can be expanded to $1 billion. Also in November 2004, we increased the capacity of our uncommitted senior secured hedged inventory facility to $400 million (with the ability to increase in the future by an incremental $100 million), and extended the maturity to November 2005.

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.

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

Organizational History

We were formed in September 1998 as a separate, publicly traded master limited partnership, to acquire and operate the midstream crude oil business and assets of Plains Resources Inc. and its wholly owned subsidiaries. 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."

Since June 2001, our 2% general partner interest has been held by Plains AAP, L.P., a Delaware limited partnership. Plains All American GP LLC, a Delaware limited liability company, is Plains AAP, L.P.'s general partner. Unless the context otherwise requires, we use the term "general partner" to refer to both Plains AAP, L.P. and Plains All American GP LLC. Plains AAP, L.P. and Plains All American GP LLC are essentially held by seven owners 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.

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 to date in 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 $332 million, including $268 million of cash (net of approximately $5.5 million subsequently returned to PAA from an indemnity escrow account) and approximately $64 million of net liabilities assumed and acquisition related costs. The Link crude oil business consists of approximately 7,000 miles of active crude oil pipeline and gathering systems, over 10 million barrels of 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.

Cal Ven Pipeline System

On May 7, 2004 we completed the acquisition of the Cal Ven Pipeline System from Cal Ven Limited, a subsidiary of Unocal Canada Limited. The total purchase price was approximately $19 million, including transaction costs. The Cal Ven Pipeline System includes approximately 195 miles of 8-inch and 10-inch gathering and mainline crude oil pipelines. The system is located in northern Alberta and 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.

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 nine months ended September 30, 2004, the system transported approximately 48,000 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 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 nine 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 $33^1/_3$% interest in Atchafalaya Pipeline, L.L.C. In December 2003, we acquired the remaining $66^2/_3$% 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, (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 Sale of Rancho Pipeline System."

Canadian Expansion

In 2001, we consummated the two transactions that enabled us to establish a presence in Canada to complement our operations in the United States. 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 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 December 31, 2003 "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 $158.4 million in cash (after post-closing adjustments), 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.

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

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 September 30, 2004, we owned approximately 15,000 miles of gathering and mainline crude oil pipelines located throughout the United States and Canada, of which approximately 13,100 miles are included in our pipeline segment. Our activities from pipeline operations generally consist of transporting crude oil for a fee and third party leases of pipeline capacity, as well as barrel exchanges and buy/sell arrangements.

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

We perform scheduled maintenance on all of our pipeline systems and make repairs and replacements when necessary or appropriate. We attempt to control corrosion of the mainlines through the use of cathodic protection, corrosion inhibiting chemicals injected into the crude stream and other protection systems typically used in the industry. Maintenance facilities containing equipment for pipe repairs, spare parts and trained response personnel are strategically located along the pipelines and in concentrated operating areas. We believe that all of our pipelines have been constructed and are maintained in all material respects in accordance with applicable federal, state, provincial and local laws and regulations, standards prescribed by the American Petroleum Institute, Canadian Standards Association 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 275,000 barrels per day (net to our interest) during the first nine 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 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 81,000 barrels per day in the first nine 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 49,000 barrels per day in the first nine 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 nine 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 nine 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 nine 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 nine 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 third quarter of 2004, volumes averaged approximately 66,000 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-inch mainline from McCamey, Texas to Healdton, Oklahoma and approximately 2.0 million barrels of storage. For the third quarter of 2004, volumes averaged approximately 109,000 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 45,000 and 10,000 average daily barrels, respectively, for the first nine 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 $3.1 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 nine months ended September 30, 2004:

	Nine Months Ended September 30, 2004	Year Ended December 31,				
		2003	2002	2001	2000	1999
	(barrels in thousands)					
Average daily volumes received from:						
Point Arguello (at Gaviota)	10	13	16	18	18	20
Santa Ynez (at Las Flores)	45	46	50	51	56	59
Total	55	59	66	69	74	79

SJV Gathering System. The SJV Gathering System is connected to most of the major fields in the San Joaquin Valley. The SJV 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 SJV 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 SJV Gathering System for the past five years and the nine months ended September 30, 2004:

	Nine Months Ended September 30, 2004	Year Ended December 31,				
		2003	2002	2001	2000	1999
	(barrels in thousands)					
Total average daily volumes	72	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 nine months of 2004 were approximately 69,000 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 52,000 barrels per day for the third 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

Capline/Capwood Pipeline System. The Capline Pipeline System, in which we acquired a 22% undivided joint interest from Shell in March 2004, is a 633-mile, 40-inch mainline crude oil pipeline originating in St. James, Louisiana, and terminating in Patoka, Illinois. The Capline Pipeline System is one of the primary transportation routes for crude oil shipped into the Midwestern U.S., accessing over 2.7 million barrels of refining capacity in PADD II, 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 has averaged approximately 148,000 barrels per day. The Capwood Pipeline System, in which we acquired a 76% undivided joint interest from Shell in March 2004, is a 57-mile, 20-inch mainline crude oil pipeline originating in Patoka, Illinois, and terminating in Wood River, Illinois. The Capwood Pipeline System has an operating capacity of 277,000 barrels per day of crude oil. Of that capacity, approximately 211,000 barrels per day are subject to 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 operatorship of the Capwood system from SPLC. Since acquisition, throughput on the interest acquired has averaged approximately 117,000 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 third quarter of 2004, volumes averaged approximately 35,000 barrels per day.

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 nine months of 2004, transported approximately 23,000 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.

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 nine months of 2004, the system transported approximately 15,000 barrels per day of crude oil and condensate.

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 nine 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.

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 nine months of 2004 were approximately 12,000 barrels per day of crude oil.

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 nine 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 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 nine months of 2004, volumes transported averaged 8,000 barrels per day.

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 nine 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.

Southwest Louisiana Pipeline System. The Southwest Louisiana Pipeline System, included in the April 2004 Link transaction, consists of approximately 254 miles of primarily 6 to 10-inch pipe. The system originates in Rapides Parish, Louisiana and delivers to the Citgo refinery in Lake Charles, LA and to Nederland, Texas. For the third quarter of 2004, volumes averaged approximately 6,000 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 third quarter of 2004, volumes averaged approximately 74,000 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 third quarter of 2004, volumes averaged approximately 29,000 barrels per day.

Canada

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 104,000 barrels of crude oil per day during the first nine months of 2004.

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 70,000 barrels of crude oil and condensate per day in the first nine months of 2004.

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 nine months of 2004, the system transported approximately 48,000 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.

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 nine months of 2004, the Cactus Lake/Bodo Pipeline System transported approximately 24,000 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.

Cal Ven Pipeline System. The Cal Ven Pipeline System, acquired in the Cal Ven acquisition in May 2004, is a provincially regulated 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. The Cal Ven Pipeline System transported approximately 16,000 barrels per day in the third quarter of 2004.

Wapella Pipeline System. The Wapella Pipeline System is a 79-mile, NEB-regulated system located in southeastern Saskatchewan and southwestern Manitoba. During the first nine months of 2004, the Wapella Pipeline System delivered approximately 13,000 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.

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 nine months of 2004, the Wascana Pipeline System transported approximately 9,000 barrels of crude oil per day.

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 nine months of 2004, the North Saskatchewan Pipeline System delivered approximately 4,400 barrels of crude oil per day into the Manito Pipeline. Our ownership interest in the North Saskatchewan Pipeline System is approximately 69%.

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;

- 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 nine months ended September 30, 2004:

	Nine Months Ended September 30, 2004	Year Ended December 31, 2003	2002	2001	2000	1999
	(barrels in thousands)					
Lease gathering	576	437	410	348	262	265
Bulk purchases[(1)]	143	90	68	46	28	138
Total volumes	719	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 approaching capacity, the producer contacts our field personnel to purchase and transport the crude oil to market. We utilize our truck fleet and gathering pipelines as well as third party pipelines, trucks and barges to transport the crude oil to market. We own or lease approximately 400 trucks used for gathering crude oil.

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

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

Crude Oil Sales. The marketing of crude oil is complex and requires current detailed knowledge of crude oil sources and end markets and a familiarity with a number of factors including grades of crude oil, individual refinery demand for specific grades of crude oil, area market price structures for the different grades of crude oil, location of customers, availability of transportation facilities and timing and costs (including storage) involved in delivering crude oil to the appropriate customer. We sell our crude oil to major integrated oil companies, independent refiners and other resellers in various types of sale and exchange transactions, 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 or over-the-counter. Through these transactions, we seek to maintain a position that is substantially balanced between crude oil purchases and sales and future delivery obligations. From time to time, we enter into various types of sale and exchange transactions including fixed price delivery contracts, floating price collar arrangements, financial swaps and crude oil futures contracts as hedging devices. Except for pre-defined inventory positions, our policy is generally to purchase only crude oil for which we have a market, to structure our sales contracts so that crude oil price fluctuations do not materially affect the segment profit we receive, and to not acquire and hold crude oil, futures contracts or other derivative products for the purpose of speculating on crude oil price changes that might expose us to indeterminable losses. In November 1999, we discovered a significant violation of this policy. As a result, we incurred an aggregate loss of approximately $181 million in unauthorized trading losses, including associated costs and legal expenses.

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

Producer Services. Crude oil purchasers who buy from producers compete on the basis of competitive prices and highly responsive services. Through our team of crude oil purchasing representatives, we maintain ongoing relationships with producers in the 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, Pennsylvania, 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 and LPG for resale and require significant extensions of credit by our suppliers of crude oil and LPG. In order to assure our ability to perform our obligations under crude oil purchase agreements, various credit arrangements are negotiated with our suppliers. These arrangements include open lines of credit directly with us, and standby letters of credit issued under our senior unsecured revolving credit facility.

When we 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. Approximately 13.6 million barrels of capacity are used in our Gathering, Marketing, Terminalling and Storage segment, and the remaining 23.4 million barrels are used in our Pipeline Operating segment. Our storage and terminalling operations increase our margins in our business of purchasing and selling crude oil and also generate revenue through a combination of storage and throughput charges to third parties. Storage fees are generated when we lease tank capacity to third parties. Terminalling fees, also referred to as throughput fees, are generated when we receive crude oil from one connecting pipeline and redeliver crude oil to another connecting carrier in volumes that allow the refinery to receive its crude oil on a ratable basis throughout a delivery period. Both terminalling and storage fees are generally earned from:

- refiners and gatherers that segregate or custom blend crudes for refining feedstocks;
- 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, with an initial tankage capacity of 2 million barrels, to capitalize on the crude oil supply and demand imbalance in the Midwest. The Cushing Terminal is also used to support and enhance the margins associated with our merchant activities relating to our lease gathering and bulk purchasing activities. See " Gathering and Marketing Operations Bulk Purchases." Since 1999, we have completed four separate expansion phases, which increased the capacity of the Cushing Terminal to a total of approximately 6.3 million barrels. The Cushing Terminal now consists of fourteen 100,000-barrel tanks, four 150,000-barrel tanks and sixteen 270,000-barrel tanks, all of which are used to store and terminal crude oil. 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 old to approximately 11 years old and the average age is approximately 5.1 years old. In contrast, we estimate that of the approximately 21 million barrels of remaining tanks in Cushing owned by third parties, the average age is approximately 50 years and of that, approximately 9 million barrels has an average age of over 70 years. We believe that provides us with a competitive advantage over our competitors. In addition, we believe that we are well positioned to accommodate construction of replacement tankage that may be required as a result of the imposition of stricter regulatory standards and related attrition among our competitors' tanks in connection with the requirements of API 653 and similar Canadian regulations. See " Regulation Pipeline and Storage Regulation."

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

We also own LPG storage facilities located in Alto, Michigan and Schaefferstown, Pennsylvania. The Alto facility is approximately 20 miles southeast of Grand Rapids. The Alto facility was acquired from Ohio-Northwest Development Inc. in 2003 and is capable of storing over 50 million gallons of LPG. The Schaefferstown facility is approximately 65 miles northwest of Philadelphia and is capable of storing over 20 million gallons of propane. We believe these facilities will further support the expansion of our LPG business in Canada and the northern tier of the U.S. as we combine the facilities' existing fee-based storage business with our wholesale propane marketing expertise. In addition, there may be opportunities to expand these facilities as LPG markets continue to develop in the region.

Crude Oil Volatility; Counter Cyclical Balance; Risk Management

Crude oil prices have historically been very volatile and cyclical, with NYMEX benchmark prices ranging from a high of over $55 per barrel in October, 2004 to as low as $10.00 per barrel over the last 14 years. Segment profit from terminalling and storage activities is dependent on the crude oil throughput volume, capacity leased to third parties, capacity that we use for our own activities, and the level of other fees generated at our terminalling and storage facilities. Segment profit from our gathering and marketing activities is dependent on our ability to sell crude oil at a price in excess of our aggregate cost. Although margins may be affected during transitional periods, these operations are not directly affected by the absolute level of crude oil prices, but are affected by overall levels of supply and demand for crude oil and relative fluctuations in market related indices.

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

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

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

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

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

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

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

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

Customers

Marathon Ashland Petroleum accounted for 12%, 10% and 11% of our revenues for each of the three years in the period ended December 31, 2003. For the nine months ended September 30, 2004, Marathon Ashland Petroleum and BP Oil Supply Company each accounted for approximately 10% of our revenues. No other customers accounted for 10% or more of our revenues during the three years ended December 31, 2003 or the nine months ended September 30, 2004. The majority of the revenues from Marathon Ashland Petroleum and BP Oil Supply Company pertain to our gathering, marketing, terminalling and storage operations. We believe that the loss of these customers would have only a short-term impact on our operating results. There can be no assurance, however, that we would be able to identify and access a replacement market at comparable margins.

Competition

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

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

Regulation

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

Pipeline and Storage Regulation

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

Federal pipeline safety rules require pipeline operators to develop and maintain a written qualification program for individuals performing covered tasks on pipeline facilities, and establish pipeline integrity management programs. In particular, since 2000, the DOT has adopted a series of rules requiring operators of interstate pipelines transporting hazardous liquids or natural gas to develop and follow an integrity management program that provides for continual assessment of the integrity of all pipeline segments that could affect so-called "high consequence areas," including high population areas, areas that are sources of drinking water, ecological resource areas that are unusually sensitive to environmental damage from a pipeline release, and commercially navigable waterways. Segments of our pipelines transporting hazardous liquids in high consequence areas are subject to these DOT rules and therefore obligate us to evaluate pipeline conditions by means of periodic internal inspection, pressure testing, or other equally effective assessment means, and to correct identified anomalies. If, as a result of our evaluation process, we determine that there is a need to provide further protection to high consequence areas, then we will be required to implement additional spill prevention, mitigation and risk control measures for our pipelines. The DOT rules also require us to evaluate and, as necessary, improve our management and analysis processes for integrating available integrity related data relating to our pipeline segments and to remediate potential problems found as a result of the required assessment and evaluation process. Costs associated with this program were approximately $1.0 million in 2003. Based on currently available information, we estimate that the costs to implement and carry out this program will be approximately $6.0 million in 2004. Our preliminary estimate for 2005 is $7.9 million. The relative increase in program cost for 2004 is primarily attributable to pipeline segments acquired in 2003 and 2004 (including the Link assets), which are subject to the new rules and which were scheduled for assessment in 2004. These costs are recurring in nature and thus will impact future periods. We will continue to refine our estimates as information from our assessments is collected. Our estimates do not include the potential costs associated with assets acquired in the future. Although we believe that our pipeline operations are in substantial compliance with currently applicable regulatory requirements, we cannot predict the potential costs associated with additional, future regulation.

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

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

The DOT has adopted API 653 as the standard for the inspection, repair, alteration and reconstruction of existing crude oil storage tanks subject to DOT jurisdiction (approximately 83% of our 37 million barrels). API 653 requires regularly scheduled inspection and repair of tanks remaining in service. Full compliance is required by 2009. We have commenced our compliance activities and, based on currently available information, we estimate that we will spend approximately $3 million in 2004 and an approximate average of $6.2 million per year from 2005 through 2009 in connection with API 653 compliance activities. Such amounts incorporate the costs associated with the assets acquired in 2003 and 2004. Our estimates do not include the potential costs associated with assets acquired in the future. We will continue to refine our estimates as information from our assessments is collected.

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

In Canada, the NEB and provincial agencies such as the Alberta Energy and Utilities Board and the Saskatchewan Industry and Resources have promulgated regulations similar to the domestic pipeline integrity management rules and API 653 standards. We estimate that the costs associated with compliance will be approximately $5.0 million in 2004. Our preliminary estimate for 2005 is $5.0 million. In addition, we expect to incur compliance costs under other regulations related to pipeline and storage tank integrity, such as operator competency programs, regulatory upgrades to our operating and maintenance systems and environmental upgrades of buried sump tanks. Our preliminary estimate for such costs for 2005 is approximately $1.0 million. These costs are recurring in nature and thus will impact future periods. We will continue to refine our estimates as information from our assessments is collected. Our estimates do not include the potential costs associated with assets acquired in the future. Although we believe that our pipeline operations are in substantial compliance with currently applicable regulatory requirements, we cannot predict the potential costs associated with additional, future regulation.

Asset acquisitions are an integral part of our business strategy. As we acquire additional assets, we may be required to incur additional costs in order to ensure that the acquired assets comply with the regulatory standards in the U.S. and Canada. The timing of such additional costs is uncertain and could vary materially from our current projections.

Transportation Regulation

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

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

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

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

On July 20, 2004, the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") issued its opinion in *BP West Coast Products, LLC v. FERC*, which upheld FERC's determination that the rates of an interstate petroleum products pipeline, SFPP, L.P. ("SFPP"), were grandfathered rates under EPAct and that SFPP's shippers had not demonstrated substantially changed circumstances that would justify modification of those rates. The court also vacated the portion of the FERC's decision applying the *Lakehead* policy, under which the FERC allowed a regulated entity organized as a master limited partnership to include in its cost-of-service an income tax allowance to the extent that entity's unitholders were corporations subject to income tax. We are uncertain what action, if any, FERC will take in response to the court's disapproval of the FERC's *Lakehead* policy and what effect, if any, such action might have on our rates should they be challenged.

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

In a subsequent FERC proceeding involving SFPP, certain shippers again challenged SFPP's grandfathered rates on the basis of substantially changed circumstances since the passage of EPAct. On March 26, 2004, the FERC issued an order in that case, finding that some of SFPP's rates were no longer grandfathered. Several of the participants in the proceeding have requested rehearing of the FERC's order, and several participants have filed petitions with the D.C. Circuit for review of the order. FERC and court action on those petitions is pending. We are uncertain whether FERC's order will remain intact and, if it does, what effect, if any, that order might have on our grandfathered rates should they be challenged.

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

Trucking Regulation

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

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

Cross Border Regulation

As a result of our Canadian acquisitions and cross border activities, we are subject to regulatory matters including export licenses, tariffs, Canadian and U.S. customs and tax issues and toxic substance certifications. Regulations include the Short Supply Controls of the Export Administration Act, the

North American Free Trade Agreement and the Toxic Substances Control Act. Violations of these license, tariff and tax reporting requirements could result in the imposition of significant administrative, civil and criminal penalties. Furthermore, the failure to comply with U.S., Canadian, state, provincial and local tax requirements could lead to the imposition of additional taxes, interest and penalties.

Environmental, Health and Safety Regulation

General

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

Water

The Oil Pollution Act, as amended ("OPA"), was enacted in 1990 and amends provisions of the Federal Water Pollution Control Act of 1972, as amended ("Clean Water Act"), and other statutes as they pertain to prevention and response to oil spills. The OPA and analogous state and Canadian federal and provincial laws subject owners of facilities to strict, joint and potentially unlimited liability for containment and removal costs, natural resource damages, and certain other consequences of an oil spill, where such spill is into navigable waters, along shorelines or in the exclusive economic zone of the U.S. The OPA establishes a liability limit of $350 million for onshore facilities. However, a party cannot take advantage of this liability limit if the spill is caused by gross negligence or willful misconduct, resulted from a violation of a federal safety, construction, or operating regulation, or if there is a failure to report a spill or cooperate in the cleanup. We believe that we are in substantial compliance with applicable OPA requirements.

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

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

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

Air Emissions

Our operations are subject to the Federal Clean Air Act, as amended, and comparable state and provincial laws. We believe that our operations are in substantial compliance with these laws in those areas in which we operate.

Amendments to the Federal Clean Air Act enacted in 1990 (the "1990 Federal Clean Air Act Amendments") as well as changes to state implementation plans for controlling air emissions in regional non-attainment areas may require most industrial operations in the U.S. to incur capital expenditures in order to meet air emission control standards developed by the U.S. Environmental Protection Agency (the "EPA") and state environmental agencies. The 1990 Federal Clean Air Act Amendments also imposed an operating permit requirement for major sources of air emissions ("Title V permits"), which applies to some of our facilities. We may be required to incur certain capital expenditures in the next several years for air pollution control equipment in connection with obtaining or maintaining permits and approvals addressing air emission related issues. Although we can provide no assurance, we believe future compliance with the 1990 Federal Clean Air Act Amendments will not have a material adverse effect on our financial condition or results of operations.

The federal government of Canada recently ratified the Kyoto Protocol. As a result, the already stringent air emissions regulations will be replaced, by 2010, with even stricter guidelines. We are currently assessing the impact the Protocol will have on our operations.

Solid Waste

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

Hazardous Substances

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

OSHA

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

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

Endangered Species Act

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

Hazardous Materials Transportation Requirements

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

Environmental Remediation

We currently own or lease, and have in the past owned or leased, properties where hazardous liquids, including hydrocarbons, are being or have been handled. Although we have utilized operating and disposal practices that were standard in the industry at the time, hazardous liquids or associated generated wastes may have been disposed of or released on or under the properties owned or leased by us or on or under other locations where these wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hazardous liquids or associated generated wastes was not under our control. These properties and the hazardous liquids or associated generated wastes disposed thereon may be subject to CERCLA, RCRA and analogous state and Canadian federal and provincial laws. Under such laws, we could be required to remove or remediate previously spilled hazardous liquids or associated generated wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial plugging operations to prevent future contamination. We are currently involved in remediation activities at a number of sites, which involve potentially significant expense.

Contamination resulting from spills of liquid hydrocarbons, including crude oil and associated generated wastes, is not unusual within the petroleum pipeline industry. Historic spills along our pipelines as well as at our terminalling and storage facilities as a result of past operations have resulted in contamination of the environment, including soils and groundwater. Properties acquired by us through acquisitions from predecessor operators, such as the properties recently acquired in the Link acquisition, oftentimes have similar impacts to soils and groundwater arising from historical operations on those properties. We are currently addressing site conditions, including soils and groundwater, at a number of our properties, including recently acquired properties, where historical or more recent operations by predecessor operators or us may have resulted in releases of hydrocarbons and other wastes. In addition, we have received contractual protections in the form of environmental indemnifications from several predecessor operators for properties acquired by us that are contaminated as a result of historical operations. These contractual indemnifications typically are subject to specific monetary and term limits that must be satisfied before indemnification will apply.

We may experience future releases of crude oil into the environment from our pipeline and storage operations, or discover past releases that were previously unidentified. Although we maintain an inspection program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to any such environmental releases from our assets may substantially affect our business. At September 30, 2004, our reserve for environmental liabilities totaled approximately $21.4 million. Approximately $13.8 million of the reserve is related to liabilities assumed as part of the Link acquisition. Although we believe our reserve is adequate, no assurance can be given that any costs incurred in excess of this reserve would not have a material adverse effect on our financial condition, results of operations or cash flows.

For instance, in connection with the Link acquisition, we identified a number of known environmental claims and estimated an amount for potential claims that are currently unknown, for which we received a purchase price reduction from Link. A substantial portion of the known environmental liabilities are associated with the former Texas New Mexico ("TNM") pipeline assets. On the effective date of the acquisition, we and TNM entered into a cost-sharing agreement whereby, on a tiered basis, we will bear $11 million of the first $20 million of pre-May 1999 known environmental issues. We will also bear the first $25,000 per site for unknown sites (capped at 100 sites). TNM will pay all costs in excess of $20 million (excluding the deductible for unknown sites). TNM's obligations are guaranteed by Shell Oil Products.

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

Allocation of environmental liability is an issue negotiated in connection with each of our acquisition transactions. In each case, we make an assessment of potential environmental exposure based on available information. Based on that assessment and relevant economic and risk factors, we determine whether to negotiate an indemnity, what the terms of any indemnity should be (for example, minimum thresholds or caps on exposure) and whether to obtain insurance, if available. The acquisitions we completed in 2003 and 2004 include a variety of provisions dealing with the allocation of responsibility for environmental costs that range from no or limited indemnities from the sellers to indemnification from sellers with defined limitations on their maximum exposure. We have not obtained insurance for any of the conditions related to our 2003 acquisitions, and only limited circumstances for our 2004 acquisitions. We believe our exposure with respect to the acquired properties is reasonable in light of all the information available to us, but can give no assurance in that regard.

We believe that the environmental reserve described above is adequate, and in conjunction with our indemnification arrangements, should prevent remediation costs from having a material adverse effect on our financial condition, results of operations, or cash flows. Nevertheless, no assurances can be made that any costs incurred in excess of this reserve or outside of the indemnifications would not have a material adverse effect on our financial condition, results of operations, or cash flows.

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

Operational Hazards and Insurance

Pipelines, terminals, trucks or other facilities or equipment may experience damage as a result of an accident or natural disaster. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. Since we and our predecessors commenced midstream crude oil activities in the early 1990s, we have maintained insurance of various types and varying levels of coverage that we consider adequate under the circumstances to cover our operations and properties. The insurance policies are subject to deductibles and retention levels that we consider reasonable and not excessive. However, such insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues. Consistent with insurance coverage generally available to the industry, our insurance policies provide limited coverage for losses or liabilities relating to pollution, with broader coverage for sudden and accidental occurrences. Over the last several years, our operations have expanded significantly, with total assets increasing over 300% since the end of 1998. At the same time that the scale and scope of our business activities have expanded, the breadth and depth of the available insurance markets have contracted. Notwithstanding what we believe is a favorable claims history, the overall cost of such insurance as well as the deductibles and overall retention levels that we maintain have increased. As a result, it is anticipated that we will elect to self insure more activities against certain of these operating hazards. Certain aspects of these conditions were exacerbated by the events of September 11, 2001, and their overall effect on the insurance industry have adversely impacted the availability and cost of certain coverages. Due to these events, insurers have excluded acts of terrorism and sabotage from our insurance policies and on certain of our key assets, we have elected to purchase a separate insurance policy for acts of terrorism and sabotage.

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

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

Title to Properties and Rights-of-Way

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

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

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

Employees

To carry out our operations, our general partner or its affiliates employed approximately 1,950 employees at September 30, 2004. None of the employees of our general partner were represented by labor unions, and our general partner considers its employee relations to be good.

Litigation

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

Alfons Sperber v. Plains Resources Inc., et al. On December 18, 2003, a putative class action lawsuit was filed in the Delaware Chancery Court, New Castle County, entitled Alfons Sperber v. Plains Resources Inc., et al. This suit, brought on behalf of a putative class of Plains All American Pipeline, L.P. common unitholders, 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.

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

Environmental. We may experience future releases of crude oil into the environment from our pipeline and storage operations, or discover past releases that were previously unidentified. Although we maintain an inspection program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to any such environmental releases from our assets may substantially affect our business. At September 30, 2004, our reserve for environmental liabilities totaled approximately $21.4 million. Approximately $13.8 million of the reserve is related to liabilities assumed as part of the Link acquisition. Although we believe our reserve is adequate, no assurance can be given that any costs incurred in excess of this reserve would not have a material adverse effect on our financial condition, results of operations or cash flows.

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

Unauthorized Trading Loss

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

MANAGEMENT

Partnership Management and Governance

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

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

Our partnership agreement provides that the general partner will manage and operate us and that, unlike holders of common stock in a corporation, unitholders will have only limited voting rights on matters affecting our business or governance. Specifically, our partnership agreement defines "Board of Directors" to mean the board of directors of Plains All American GP LLC, which is elected by the members of Plains All American GP LLC, and not by the unitholders. Thus, the corporate governance of Plains All American GP LLC is, in effect, the corporate governance of our partnership, subject in all cases to any specific unitholder rights contained in our partnership agreement. Because we are a limited partnership, the new listing standards of the New York Stock Exchange do not require that we or our general partner have a majority of independent directors or a nominating or compensation committee of the board of directors.

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

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

Mr. Everardo Goyanes, the Chairman of our Audit Committee, is the Chief Executive Officer of Liberty Energy Corporation ("LEC"), a subsidiary of Liberty Mutual Insurance Company. Mr. Goyanes is an employee of Liberty Mutual Insurance Company. LEC makes investments in producing properties, from some of which Plains Marketing, L.P. buys the production. LEC does not operate the properties in which it invests. Plains Marketing pays the same amount per barrel to LEC that it pays to other interest owners in the properties. In 2003, the amount paid to LEC by Plains Marketing was approximately $1,085,000 ($974,000 net of severance taxes),

Mr. J. Taft Symonds, a member of our Audit Committee, is a director and the non-executive Chairman of the Board of Tetra Technologies, Inc. ("Tetra"). A subsidiary of Tetra owns crude oil producing properties, from some of which Plains Marketing buys the production. We paid approximately $7.9 million to the Tetra subsidiary in 2003. Until July 2004, Mr. Symonds was also a director of Plains Resources Inc., with whom Plains Marketing has a marketing arrangement. We paid approximately $25.7 million to Plains Resources in 2003, and recognized segment profit of approximately $0.2 million. Mr. Symonds was not and is not an officer of Tetra or Plains Resources, and does not participate in operational decision making, including decisions concerning selection of crude oil purchasers or entering into sales or marketing arrangements.

We have a compensation committee, which reviews and makes recommendations regarding the compensation for the executive officers and administers our equity compensation plans for officers and key employees. We also have a governance committee that periodically reviews our governance guidelines. In addition, our partnership agreement provides for the establishment/activation of a conflicts committee as circumstances warrant to review conflicts of interest between us and our general partner or the owners of our general partner. Such a committee would consist of a minimum of two members, none of whom are officers or employees of our general partner or directors, officers or employees of its affiliates. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our general partner of any duties owed to us or our unitholders.

Our committee charters and governance guidelines are available on our website at www.paalp.com.

Directors and Executive Officers

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

Name	Age (as of 11/30/04)	Position with Our General Partner
Greg L. Armstrong[(1)]	46	Chairman of the Board, Chief Executive Officer and Director
Harry N. Pefanis	47	President and Chief Operating Officer
Phillip D. Kramer	48	Executive Vice President and Chief Financial Officer
George R. Coiner	54	Senior Group Vice President
W. David Duckett	49	President PMC (Nova Scotia) Company
Mark F. Shires	47	Senior Vice President Operations
Alfred A. Lindseth	35	Senior Vice President Technology, Process & Risk Management
Lawrence J. Dreyfuss	50	Vice President, Associate General Counsel and Assistant Secretary; Vice President, General Counsel and Secretary of PMC (Nova Scotia) Company (the general partner of Plains Marketing Canada, L.P.)
James B. Fryfogle	53	Vice President Lease Operations
Jim G. Hester	45	Vice President Acquisitions
Tim Moore	47	Vice President, General Counsel and Secretary
John F. Russell	55	Vice President Pipeline Operations
Al Swanson	40	Vice President and Treasurer
Tina L. Val	35	Vice President Accounting and Chief Accounting Officer
Troy E. Valenzuela	43	Vice President Environmental, Health and Safety
John P. vonBerg	50	Vice President Trading
David N. Capobianco[(1)]	35	Director and Member of Compensation Committee
Everardo Goyanes	60	Director and Member of Audit* Committee
Gary R. Petersen[(1)]	58	Director and Member of Compensation* Committee
John T. Raymond[(1)]	34	Director
Robert V. Sinnott[(1)]	55	Director and Member of Compensation Committee
Arthur L. Smith	52	Director and Member of Audit and Governance* Committees
J. Taft Symonds	65	Director and Member of Governance and Audit Committees

* Indicates chairman of committee

(1) The Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC (as amended, the "LLC Agreement") specifies that the Chief Executive Officer of the general partner will be a member of the board of directors. The LLC Agreement also provides that certain of the owners of our general partner have the right to designate a member of our board of directors. Mr. Capobianco has been designated by Plains Holdings Inc. Mr. Petersen has been designated by E-Holdings III, L.P., an affiliate of EnCap Investments L.P., of which he is a Managing Director. Mr. Raymond has been

designated by Sable Investments, L.P. Sable Investments, L.P. is controlled by James M. Flores, a director of Vulcan Energy Corporation and also the Chairman, President and Chief Executive Officer of PXP. Mr. Sinnott has been designated by KAFU Holdings, L.P., which is affiliated with Kayne Anderson Investment Management, Inc., of which he is a Vice President. See "Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters Beneficial Ownership of General Partner Interest."

Greg L. Armstrong has served as Chairman of the Board and Chief Executive Officer since our formation. He has also served as a director of our general partner or former general partner since our formation. In addition, he was President, Chief Executive Officer and director of Plains Resources from 1992 to May 2001. He previously served Plains Resources as: President and Chief Operating Officer from October to December 1992; Executive Vice President and Chief Financial Officer from June to October 1992; Senior Vice President and Chief Financial Officer from 1991 to 1992; Vice President and Chief Financial Officer from 1984 to 1991; Corporate Secretary from 1981 to 1988; and Treasurer from 1984 to 1987. Mr. Armstrong is also a director of Varco International, Inc.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

John P. vonBerg has served as Vice President of Trading since May 2003 and Director of these activities since joining us in January of 2002. He was with Genesis Energy in differing capacities as a

Director, Vice Chairman, President and CEO from 1996 through 2001, and from 1993 to 1996 he served as a Vice President and a Crude Oil Manager for Phibro Energy USA. Mr. VonBerg began his career with Marathon Oil Company, spending 13 years in various disciplines.

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

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

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

John T. Raymond has served as a director since June 2001. He has been a director and the Chief Executive Officer of Vulcan Energy Corporation since July 2004. Mr. Raymond has served as President and Chief Executive Officer of Plains Resources since December 2002. Prior thereto, Mr. Raymond served as Executive Vice President and Chief Operating Officer of Plains Resources from May 2001 to November 2001 and President and Chief Operating Officer since November 2001. Mr. Raymond also served as President and Chief Operating Officer of Plains Exploration and Production from December 2002 to March 2004. He was Director of Corporate Development of Kinder Morgan, Inc. from January 2000 to May 2001. He served as Vice President of Corporate Development of Ocean Energy, Inc. from April 1998 to January 2000. He was Vice President of Howard Weil Labouisse Friedrichs, Inc. from 1992 to April 1998.

Robert V. Sinnott has served as a director of our general partner or former general partner since September 1998. Mr. Sinnott has been a Senior Managing Director of Kayne Anderson Capital Advisors, L.P. (an investment management firm) since 1996, and was a Managing Director from 1992 to 1996. He is also a vice president of Kayne Anderson Investment Management Inc., the general partner of Kayne Anderson Capital Advisors, L.P. He was Vice President and Senior Securities Officer of the Investment Banking Division of Citibank from 1986 to 1992. He is also a director of Glacier Water Services, Inc. (a vended water company). Mr. Sinnott was previously a director of Plains Resources.

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

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

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

Name	Age (as of 11/30/04)	Position with Our General Partner/Canadian General Partner
Management Team/Other Officers:		
A. Patrick Diamond	31	Manager Special Projects
Canadian Officers:		
D. Mark Alenius	45	Vice President and Chief Financial Officer of PMC (Nova Scotia) Company
Ralph R. Cross	49	Vice President Business Development of PMC (Nova Scotia) Company
Ronald H. Gagnon	46	Vice President Operations of PMC (Nova Scotia) Company
M.D. (Mike) Hallahan	44	Vice President Crude Oil of PMC (Nova Scotia) Company
Richard (Rick) Henson	50	Vice President Corporate Services of PMC (Nova Scotia) Company
Ron F. Wunder	36	Vice President LPG of PMC (Nova Scotia) Company

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

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

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

Ronald H. Gagnon has been Vice President, Operations of PMC (Nova Scotia) Company since January 2004, Managing Director, Information and Transportation Services from June 2003 to January 2004 and Director, Information Services from July 2001 to May 2003. Mr. Gagnon was previously with CANPET Energy Group Inc. since 1987, where he served in various capacities, including Vice President, Producer Services.

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

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

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

Executive Compensation

The following table sets forth certain compensation information for our Chief Executive Officer and the four other most highly compensated executive officers in 2003 (the "Named Executive Officers"). Messrs. Armstrong, Pefanis and Kramer were compensated by Plains Resources prior to July 2001. However, we reimburse our general partner and its affiliates (and, for a portion of 2001, we reimbursed our former general partner and its affiliates, which included Plains Resources) for expenses incurred on our behalf, including the costs of officer compensation allocable to us. The Named Executive Officers have also received certain equity-based awards from our general partner and from our former general partner and its affiliates, which awards (other than awards under the Long-Term

Incentive Plan) are not subject to reimbursement by us. See " Long-Term Incentive Plan" and "Certain Relationships and Related Transactions Transactions with Related Parties."

		Annual Compensation			Long-Term Compensation
Name and Principal Position	Year	Salary	Bonus	Other Compensation	LTIP Payout
Greg L. Armstrong Chairman and CEO	2003 2002 2001	$ 330,000 330,000 165,000[(1)]	$ 1,000,000 600,000 450,000	$ 12,000[(2)] 11,000[(2)] [(1)(2)]	$
Harry N. Pefanis President and COO	2003 2002 2001	$ 235,000 235,000 117,500[(1)]	$ 800,000 475,000 350,000	$ 12,000[(2)] 11,000[(2)] [(1)(2)]	$ 452,400
Phillip D. Kramer Executive V.P. and CFO	2003 2002 2001	$ 200,000 200,000 100,000[(1)]	$ 500,000 275,000 100,000	$ 12,000[(2)] 11,000[(2)] [(1)(2)]	$
George R. Coiner Senior Group Vice President	2003 2002 2001	$ 200,000 200,000 175,000	$ 719,600[(3)] 451,000[(4)] 430,100[(5)]	$ 12,000[(2)] 11,000[(2)] 10,500[(2)]	$ 226,200
W. David Duckett[(6)] President PMC (Nova Scotia Company)	2003 2002 2001	$ 190,658 163,891 80,020	$ 724,883 270,070 15,182	$	$

(1) Salary amounts shown for the year 2001 reflect compensation paid by our general partner and reimbursed by us for the last six months of 2001. Until July 2001, Messrs. Armstrong, Pefanis and Kramer were employed and compensated by Plains Resources, which owned our former general partner. We reimbursed Plains Resources for the portion of their compensation allocable to us. In 2001, approximately $218,000, $655,000 and $127,000 was reimbursed to our former general partner and its affiliates for salary and bonus (for the year 2000) for the services of Messrs. Armstrong, Pefanis and Kramer, respectively. See "Certain Relationships and Related Transactions Transactions with Related Parties."

(2) Prior to the transfer of a majority of our general partner interest in 2001 (the "General Partner Transition"), Plains Resources matched 100% of employees' contribution to its 401(k) Plan (subject to certain limitations in the plan), with such matching contribution being made 50% in cash and 50% in common stock of Plains Resources (the number of shares for the stock match being based on the market value of the Common Stock at the time the shares were granted). After the General Partner Transition, our general partner matches 100% of employees' contributions to its 401(k) Plan in cash, subject to certain limitations in the plan.

(3) Includes quarterly bonuses aggregating $469,600 and an annual bonus of $250,000. The annual bonus is payable 60% in 2004, 20% in 2005 and 20% in 2006.

(4) Includes quarterly bonuses aggregating $361,000 and an annual bonus of $90,000. The annual bonus was paid 60% in 2003, and will be paid 20% in 2004 and 20% in 2005.

(5) Includes quarterly bonuses aggregating $310,100 and an annual bonus of $120,000. The annual bonus was paid 60% in 2002, and 20% in 2003, and 20% will be paid in 2004.

(6) Salary and bonus for Mr. Duckett are presented in U.S. dollar equivalent, based on the exchange rates in effect on the dates payments were made. Mr. Duckett commenced employment on July 1, 2001.

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

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

Mr. Pefanis is employed as President and Chief Operating Officer. The initial three-year term of Mr. Pefanis' employment agreement commenced on June 30, 2001, and is automatically extended for one year on June 30 of each year (such that the term is reset to three years) unless Mr. Pefanis receives notice from the Chairman of the Board of Directors that the Board has elected not to extend the agreement. Mr. Pefanis has agreed, during the term of the agreement and for one year thereafter, not to disclose (subject to typical exceptions) any confidential information obtained by him while employed under the agreement. The agreement provides for a current base salary of $235,000 per year, subject to annual review. The provisions in Mr. Pefanis' agreement with respect to termination, change in control and related payment obligations are substantially similar to the parallel provisions in Mr. Armstrong's agreement.

1998 Long-Term Incentive Plan

Our general partner has adopted the Plains All American GP LLC 1998 Long-Term Incentive Plan (the "LTIP") for employees and directors of our general partner and its affiliates who perform services for us. The LTIP consists of two components, a restricted ("phantom") unit plan and a unit option plan. The LTIP currently permits the grant of phantom units and unit options covering an aggregate of 1,425,000 common units delivered upon vesting of such phantom units or unit options. No options have been granted under the unit option plan. The plan is administered by the Compensation Committee of our general partner's board of directors. Our general partner's board of directors in its discretion may terminate the LTIP at any time with respect to any common units for which a grant has not yet been made. Our general partner's board of directors also has the right to alter or amend the LTIP or any part of the plan from time to time, including, subject to any applicable NYSE listing requirements, increasing the number of common units with respect to which awards may be granted; provided, however, that no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of such participant.

Restricted Unit Plan. A restricted unit is a "phantom" unit that entitles the grantee to receive, upon the vesting of the phantom unit, a common unit (or cash equivalent, depending on the terms of the grant). A substantial number of phantom units have vested in 2003 and 2004. As of September 30, 2004, giving effect to vested grants, grants of approximately 134,000 unvested phantom units remain outstanding to employees, officers and directors of our general partner. The Compensation Committee may, in the future, make additional grants under the plan to employees and directors containing such terms as the Compensation Committee shall determine.

If a grantee terminates employment or membership on the board for any reason, the grantee's phantom units will be automatically forfeited unless, and to the extent, the Compensation Committee provides otherwise. Vested phantom units may be satisfied in common units or cash equivalents. Common units to be delivered upon the vesting of rights may be common units acquired by our general partner in the open market or in private transactions, common units already owned by our general partner, or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the cost incurred in acquiring common units. In addition, over the term of the plan we may issue up to 975,000 new common units to satisfy delivery obligations under the grants, less any common units issued upon exercise of unit options under the plan (see below). When we issue new common units upon vesting of the phantom units, the total number of common units outstanding increases. The compensation committee, in its discretion, may grant tandem distribution equivalent rights with respect to phantom units.

Other than grants to directors (discussed below), none of the phantom units vested until November 2003. Since that time, approximately 927,000 phantom units have vested. Including grants to directors, approximately 418,000 units have been purchased and delivered or issued in satisfaction of vesting, after payment of cash-equivalents and netting for taxes. As a result of the vesting of these awards, we recognized an expense of approximately $28.8 million as of December 31, 2003 and an expense of approximately $4.2 million as of September 30, 2004.

New tax rules concerning deferred compensation will become effective January 1, 2005. Until Treasury Regulations are issued, the application of this new law to the LTIP is unclear. We intend to operate the LTIP, and make any amendments to it that may be necessary, for the LTIP and awards granted thereunder to comply with this new law.

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

In 2000, the three non-employee directors of our former general partner (Messrs. Goyanes, Sinnott and Smith) were each granted 5,000 phantom units. These units vested and were paid in connection with the transfer of the general partner interest in 2001. Additional grants of 5,000 phantom units were made in 2002 to each non-employee director of our general partner. These units vest and are payable in 25% increments on each anniversary of June 8, 2001. The first three vestings took place on June 8 of 2002, 2003 and 2004. See " Compensation of Directors."

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

		November 2003 Vesting		February 2004 Vesting		May 2004 Vesting		August 2004 Vesting		Remaining Unvested Grants(2)	
Name	**Total Units**	**Units**	**Value(1)**	**Units**	**Value(1)**	**Units**	**Value(1)**	**Units**	**Value(1)**	**Units**	**Value(3)**
Greg L. Armstrong	70,000			17,500	$ 551,250	17,500	$ 580,650	17,500	$ 560,700	17,500	$ 629,650
Harry N. Pefanis	70,000	15,000	$ 452,400	47,500	$ 1,511,550	2,500	$ 82,950	2,500	$ 80,100	2,500	$ 89,950
Phillip D. Kramer	50,000			12,500	$ 393,750	12,500	$ 414,750	12,500	$ 400,500	12,500	$ 449,750
George R. Coiner	67,500	7,500	$ 226,200	31,875	$ 1,028,869	9,375	$ 311,063	9,375	$ 300,375	9,375	$ 337,313
W. David Duckett											

(1) As of vesting dates.

(2) With respect to remaining grants, vesting is contingent upon our achieving a specified distribution threshold of $2.50 annualized.

(3) As if vested on September 30, 2004.

Unit Option Plan. The unit option plan under our LTIP currently permits the grant of options covering common units. No grants have been made under the unit option plan to date. However, the Compensation Committee may, in the future, make grants under the plan to employees and directors containing such terms as the committee shall determine, provided that unit options have an exercise price equal to the fair market value of the units on the date of grant.

Upon exercise of a unit option, our general partner may deliver common units acquired by it in the open market or in private transactions or use common units already owned by our general partner, or any combination of the foregoing. In addition, we may issue up to 975,000 new common units to satisfy delivery obligations under the grants, less any common units issued upon vesting of restricted units under the plan. Our general partner will be entitled to reimbursement by us for the difference between the cost incurred by our general partner in acquiring such common units and the proceeds received by our general partner from an optionee at the time of exercise. Thus, the cost of the unit options will be borne by us. If we issue new common units upon exercise of the unit options, the total number of common units outstanding will increase, and our general partner will remit to us the proceeds received by it from the optionee upon exercise of the unit option.

2005 Long-Term Incentive Plan

Our board of directors has unanimously approved, subject to the approval of our unitholders, our 2005 Long-Term Incentive Plan (the "2005 LTIP"). The 2005 LTIP would provide awards to our employees and directors. Awards contemplated under the 2005 LTIP include phantom units, restricted units, unit appreciation rights and unit options, as determined by the Compensation Committee (each an "Award"). If approved by our unitholders, up to 3,000,000 units may be issued in satisfaction of Awards. Certain Awards may also include, in the discretion of the Compensation Committee, a "distribution equivalent right," or "DER," that entitles the grantee to a cash payment, either while the Award is outstanding or upon vesting, equal to any cash distributions paid on a unit while the Award is outstanding. As of November, 2004, approximately 2,000 individuals (of which we expect that approximately 200 to 250 would be participants) would be eligible for Awards under the 2005 LTIP.

Other Equity Grants

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

Compensation of Directors

Each director of our general partner who is not an employee of our general partner is currently paid an annual retainer fee of $45,000, plus reimbursement for out-of-pocket expenses related to meeting attendance. In 2001, Messrs. Goyanes and Smith each received $10,000 for their service on a special committee of the Board of Directors of our former general partner. Mr. Armstrong is otherwise compensated for his services as an employee and therefore receives no separate compensation for his services as a director. Each committee chairman (other than the Audit Committee) receives $2,000 annually. The chairman of the Audit Committee receives $30,000 annually, and the other members of the Audit Committee receive $15,000 annually. Mr. Petersen assigns any compensation he receives in his capacity as a director to EnCap Energy Capital Fund III, L.P., which is controlled by EnCap Investments L.P., of which Mr. Petersen is a Managing Director. Mr. Capobianco assigns any compensation he receives in his capacity as a director to Vulcan Capital.

In 2000, Messrs. Goyanes, Sinnott and Smith, as directors of our former general partner, received a grant of 5,000 phantom units each under our LTIP. The phantom units vested and were paid in 2001 in connection with the consummation of the General Partner Transition. Each non-employee director of our general partner at the time received a grant of 5,000 phantom units in 2002. Mr. Peterson's grant was subsequently converted into cash payment of equivalent value to EnCap III. The units vest and are payable in 25% increments annually on each anniversary of June 8, 2001. The final vesting will occur in June 2005.

Reimbursement of Expenses of Our General Partner and its Affiliates

We do not pay our general partner a management fee, but we do reimburse our general partner for all expenses incurred on our behalf, including the costs of employee, officer and director compensation and benefits, as well as all other expenses necessary or appropriate to the conduct of our business. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion. Prior to July 1, 2001, an allocation was made for overhead associated with officers and employees who divided time between us and Plains Resources. As a result of the transfer of the general partner interest (and related transactions) in 2001, all of the employees and officers of the general partner now devote 100% of their efforts to our business and there are no allocated expenses. See "Certain Relationships and Related Transactions."

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Our General Partner

Our operations and activities are managed by, and our officers and personnel are employed by, our general partner (or, in the case of our Canadian operations, PMC (Nova Scotia) Company). Prior to the consummation of the General Partner Transition, some of the senior executives who managed our business also managed and operated the business of Plains Resources. The transition of employment of such executives to our general partner was effected on June 30, 2001. We do not pay our general partner a management fee, but we do reimburse our general partner for all expenses incurred on our behalf.

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

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

Annual Distribution Per Unit	Distribution to Unitholders(1)(2)	Distribution to GP(1)(2)(3)	Total Distribution(1)	GP Percentage of Total Distribution
$1.80	$ 126,000	$ 2,571	$ 128,571	2.0%
$1.98	$ 138,600	$ 4,795	$ 143,395	3.3%
$2.31	$ 161,700	$ 12,495	$ 174,195	7.2%
$2.40	$ 168,000	$ 14,595	$ 182,595	8.0%
$2.60	$ 182,000	$ 19,262	$ 201,262	9.6%
$2.80	$ 196,000	$ 28,595	$ 224,595	12.7%
$3.00	$ 210,000	$ 42,595	$ 252,595	16.9%

(1) In thousands.

(2) Assumes 70,000,000 units outstanding. Actual number of units outstanding as of September 30, 2004 was 67,293,108. An increase in the number of units outstanding would increase both the distribution to unitholders and the distribution to the general partner of any given level of distribution per unit.

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

Transactions with Related Parties

General

Before the General Partner Transition, Plains Resources indirectly owned and controlled our former general partner interest. In 2001, our former general partner and its affiliates incurred $31.2 million of direct and indirect expenses on our behalf, which we reimbursed. Of this amount, approximately $218,000, $655,000 and $127,000 represented allocated salary and bonus (for the year 2000) reimbursement for the services of Messrs. Armstrong, Pefanis and Kramer, respectively, as officers of our former general partner.

As of September 30, 2004 Vulcan Energy, through its wholly owned subsidiary Plains Resources, owned an effective 44% of our general partner interest, as well as approximately 18.4% of our outstanding limited partner units. Mr. John Raymond, one of our directors, is a director and the Chief Executive Officer of Vulcan Energy. Mr. Raymond was designated as a member of our board by Sable Investments, L.P., which is controlled by Mr. James C. Flores. Mr. Flores is a director of Vulcan

Energy, the 100% owner of Plains Resources, and is the Chief Executive Officer of Plains Exploration and Production Company ("PXP"). We have ongoing relationships with Plains Resources. These relationships include but are not limited to:

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

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

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

- a Marketing Agreement with Plains Resources that provides for the marketing of Plains Resources' equity crude oil production (including its subsidiaries that conduct exploration and production activities.). Under the Marketing Agreement, we purchase for resale at market prices of Plains Resources equity production for a fee of $0.20 per barrel. The fee is subject to adjustment in November 2006 based on then-existing market conditions. For the year ended December 31, 2003, Plains Resources produced approximately 2,000 barrels per day that were subject to the Marketing Agreement. We paid approximately $25.7 million for such production and recognized segment profit of approximately $0.2 million under the terms of that agreement. In our opinion, these purchases were made at prevailing market prices. Because Plains Resources divested itself of most of its producing properties at the end of 2002, we do not expect material amounts of crude oil to be subject to this agreement. As currently in effect, the Marketing Agreement (as well as the Omnibus Agreement described above) will terminate upon a "change of control" of Plains Resources or our general partner. The recent purchase of Plains Resources by Vulcan Energy would have constituted a change of control under both the Marketing Agreement and the Omnibus Agreement. In July 2004, we amended and restated the Marketing Agreement and the Omnibus Agreement to except the Vulcan transaction from the change of control provisions.

On December 18, 2002, Plains Resources completed a spin-off of one of its subsidiaries, PXP, to its shareholders. PXP is a successor participant to the Plains Resources Marketing agreement. For the year ended December 31, 2003, PXP produced approximately 26,000 barrels per day that were subject to the Marketing Agreement. We paid approximately $277.9 million for such production and recognized segment profit of approximately $1.7 million. In our opinion, these purchases were made at prevailing market prices. We are also party to a Letter Agreement with Stocker Resources, L.P. (now PXP) that provides that if the Marketing Agreement terminates before our crude oil sales agreement with Tosco Refining Co. terminates, PXP will continue to sell and we will continue to purchase PXP's equity crude oil production from the Arroyo Grande field (now owned by a subsidiary of PXP) under the same terms as the Marketing Agreement until our Tosco sales agreement terminates. In July 2004, we amended and restated the Marketing Agreement to, among other things, reflect the change in parties as a result of the spin-off. We sell PXP's crude under sales contracts that range from one year to seven years in length. In October, 2004, we further amended the PXP Marketing Agreement to exclude any newly acquired properties and to adjust the marketing fee to $0.15 per barrel for any new contracts entered into after January 1, 2005.

Transaction Grant Agreements

In connection with our initial public offering, our former general partner, at no cost to us, agreed to transfer, subject to vesting, approximately 400,000 of its affiliates' common units (including distribution equivalent rights attributable to such units) to certain key officers and employees of our former general partner and its affiliates, including Messrs. Armstrong, Pefanis, Coiner and Kramer. Approximately 70,000 units vested in 2000, and the remainder in 2001. The value of the units and associated distribution equivalent rights that vested under the Transaction Grant Agreements for all grantees in 2001 was $5.7 million. Although we recorded noncash compensation expenses with respect to these vestings, the compensation expense incurred in connection with these grants was funded by our former general partner, without reimbursement by us.

Long-Term Incentive Plan

Our general partner has adopted the Plains All American GP LLC 1998 Long-Term Incentive Plan for employees and directors of our general partner and its affiliates who perform services for us. The LTIP consists of two components, a restricted unit plan and a unit option plan. The LTIP permits the grant of restricted units and unit options covering delivery of an aggregate of 1,425,000 common units. The plan is administered by the compensation committee of our general partner's board of directors.

A restricted unit is a "phantom" unit that entitles the grantee to receive a common unit (or cash equivalent) upon the vesting of the phantom unit. As of September 30, 2004, approximately 418,000 common units have been issued or purchased and delivered upon vesting and grants of approximately 134,000 phantom units remain outstanding to employees, officers and directors of our general partner. See "Management Executive Compensation."

Performance Option Plan

In connection with the General Partner Transition, the owners of the general partner (other than PAA Management, L.P.) contributed an aggregate of 450,000 subordinated units (now converted into common units) to the general partner to provide a pool of units available for the grant of options to management and key employees. In that regard, the general partner adopted the Plains All American 2001 Performance Option Plan, pursuant to which options to purchase approximately 391,000 units have been granted. Of this amount, 75,000, 55,000, 45,000 and 42,500 were granted to Messrs. Armstrong, Pefanis, Kramer and Coiner, respectively, and approximately 346,000 to executive officers as a group. These options vest in 25% increments based upon achieving quarterly distribution levels on our units of $0.525, $0.575, $0.625 and $0.675 ($2.10, $2.30, $2.50 and $2.70, annualized). The first such level was reached in 2002, and 25% of the options vested. The second level was reached in 2004, and an incremental 25% of the options vested. The options will vest in their entirety immediately upon a change in control (as defined in the grant agreements). The original purchase price under the options was $22 per subordinated unit, declining over time in an amount equal to 80% of each quarterly distribution per unit. As of September 30, 2004, the purchase price was $16.39 per unit. The terms of future grants may differ from the existing grants. Because the units underlying the plan were contributed to the general partner, we will have no obligation to reimburse the general partner for the cost of the units upon exercise of the options.

Stock Option Replacement

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

CANPET Energy Group Inc.

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

Tank Car Lease and CANPET

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

Class B Common Units

In May 1999, we sold 1,307,190 unregistered Class B common units (the "Class B common units") to our general partner at the time, Plains All American Inc., a wholly owned subsidiary of Plains Resources Inc., pursuant to Rule 4(2) of the Securities Act. We received $19.125 per Class B common unit, a price equal to the then-market value of our common units for total proceeds of approximately $25 million. We used the net proceeds from the offering to defray costs associated with our acquisition of Scurlock Permian LLC and certain other pipeline assets from Marathon Ashland Petroleum LLC.

Class C Common Units

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

Other

An affiliate of KAFU Holdings, L.P., an owner of our general partner interest, participated in our December 2003 and July 2004 equity offerings. In the aggregate for both offerings, it earned approximately $672,000 in commissions for its participation.

DESCRIPTION OF NOTES

We issued the outstanding Notes, and will issue the new Notes, under an indenture (the "Base Indenture") dated September 25, 2002, among us, the subsidiary guarantors and Wachovia Bank, National Association, as trustee, and two supplemental indentures thereto (each applicable to one of the series of the Notes) dated as of August 12, 2004 (each such supplemental indenture, together with the Base Indenture, the "Indenture"). We refer to both the new Notes and the outstanding Notes in this description as the "Notes."

The Notes constitute two new series of debt securities under the Indenture. The terms of the Notes include those stated in the Indenture and those made part of the Indenture by reference to the Trust Indenture Act of 1939, as amended. We urge you to read the Indenture because it, and not this description, defines your rights as a holder of Notes. A copy of the Indenture is filed as an exhibit to the registration statement of which this prospectus is a part. Capitalized terms that are used in this prospectus have the meanings assigned to them in the Indenture, and we have included some of those definitions at the end of this section. See " Definitions."

We have summarized some of the material provisions of the Notes and the Indenture below. The following description of the Notes is not complete and is subject to, and is qualified in its entirety by reference to, all the provisions of the Indenture.

General Description of the Notes and the Guarantees

The Notes of each series are:

- our senior unsecured indebtedness ranking equally in right of payment with the Notes of the other series and with all of our existing and future unsubordinated debt;
- unconditionally guaranteed by the subsidiary guarantors;
- a new series of debt securities issued under the Indenture;
- non-recourse to our general partner;
- senior in right of payment to any of our future subordinated debt;
- effectively junior to any of our existing and future secured debt to the extent of the security for that debt; and
- effectively junior to any existing and future debt of our subsidiaries that do not guarantee the Notes.

Initially our obligations under the Notes are jointly and severally guaranteed by all of the existing subsidiaries of Plains All American Pipeline other than PAA Finance Corp., and those considered minor, which we sometimes refer to collectively as the "non-guarantor subsidiaries." Each guarantee by a subsidiary guarantor of the Notes is:

- a general unsecured obligation of that subsidiary guarantor;
- equal in right of payment with all other existing and future unsubordinated debt of that subsidiary guarantor;
- senior in right of payment to any future subordinated debt of that subsidiary guarantor; and
- effectively junior to any secured debt of that subsidiary guarantor, to the extent of the security for that debt.

As of September 30, 2004, the Notes and the guarantees would have been effectively subordinated to $59.5 million of short-term secured indebtedness. See "Risk Factors Risks Related to the Exchange

Offers and the Notes Your right to receive payments on the Notes and the guarantees is unsecured and will be effectively subordinated to our existing and future secured indebtedness as well as to any existing and future indebtedness of our subsidiaries that do not guarantee the Notes."

The Indenture does not limit the aggregate principal amount of debt securities that may be issued thereunder and provides that debt securities may be issued thereunder from time to time in one or more additional series. Except to the extent described below, the Indenture does not limit our ability or the ability of our subsidiaries to incur additional indebtedness.

Further Issuances

We may, from time to time, without notice to or the consent of the holders of the Notes, create and issue additional notes ranking equally and ratably with the Notes in all respects (except for the payment of interest accruing prior to the issue date of such additional notes), so that such additional notes form a single series with either series of the Notes and have the same terms as to status, redemption or otherwise as that series of Notes. If we issue such additional notes of either series prior to the completion of the exchange offers, the period of the resale restrictions applicable to any Notes of that series previously offered and sold in reliance on Rule 144A under the Securities Act will be automatically extended to the last day of the period of any resale restrictions imposed on any such additional notes.

Principal, Maturity and Interest

We have issued the outstanding Notes of each series in an initial aggregate principal amount of $175 million, and the new Notes of each series, together with any outstanding Notes of the same series that are not exchanged for new Notes, will aggregate $175 million in principal amount. The 2009 Notes will mature on August 15, 2009, and the 2016 Notes will mature on August 15, 2016. The 2009 Notes and the 2016 Notes bear interest at the annual rate of 4.750% and 5.875%, respectively. Additional interest may also accrue on the Notes of either series in the circumstances described under "Exchange Offers." All references to "interest" in this description of Notes include any such additional interest. Interest on the Notes accrues from August 12, 2004 and is payable semi-annually in arrears on February 15 and August 15 of each year, commencing February 15, 2005. We will make each interest payment to the holders of record at the close of business on the February 1 and August 1 preceding such interest payment dates. Interest will be computed on the basis of a 360-day year consisting of twelve 30-day months. We will issue the Notes in denominations of $2,000 and integral multiples of $2,000.

No Liability of General Partner

Plains All American Pipeline's general partner and its directors, officers, employees and partners (in their capacities as such) will not have any liability for our obligations under the Notes. In addition, the Managing General Partner, and its directors, officers, employees and members, will not have any liability for our obligations under the Notes. By accepting the Notes, each holder waives and releases all such liability. The waiver and release are part of the consideration for the issuance of the Notes. This waiver may not be effective, however, to waive liabilities under the federal securities laws, and it is the view of the SEC that such a waiver is against public policy.

The Guarantees

Initially, our payment obligations under the Notes are jointly and severally guaranteed by all existing Subsidiaries of Plains All American Pipeline other than the non-guarantor subsidiaries. The obligations of each subsidiary guarantor under its guarantee are limited to the maximum amount that will, after giving effect to all other contingent and fixed liabilities of the subsidiary guarantor and to any collections from or payments made by or on behalf of any other subsidiary guarantor in respect of the obligations of the other subsidiary guarantor under its guarantee, result in the obligations of the subsidiary guarantor under the guarantee not constituting a fraudulent conveyance or fraudulent transfer under federal or state law.

Provided that no default shall have occurred and shall be continuing under the Indenture, a subsidiary guarantor will be unconditionally released and discharged from its guarantee:

- upon any sale or other disposition of all or substantially all of the assets of that subsidiary guarantor, including by way of merger, consolidation or otherwise, to any person that is not our affiliate (provided such sale or other disposition is not prohibited by the Indenture);

- upon any sale or other disposition of all of our direct or indirect equity interests in that subsidiary guarantor to any person that is not our affiliate; or

- following delivery of a written notice of the release from the guarantee by us to the trustee, upon the release of all guarantees by the subsidiary guarantor of any debt of ours and any Subsidiary of Plains All American Pipeline (other than debt securities issued under the Indenture on or after the Issue Date).

If at any time after the issuance of the Notes, including following any release of a subsidiary guarantor from its guarantee under the Indenture, a Subsidiary of Plains All American Pipeline (including any future Subsidiary) guarantees any of our debt or any debt of Plains All American Pipeline's other Subsidiaries, we will cause such Subsidiary to guarantee the Notes in accordance with the Indenture by simultaneously executing and delivering a supplemental indenture.

Optional Redemption

The 2009 Notes and the 2016 Notes are redeemable, in whole or in part, at our option at any time and from time to time prior to maturity at a redemption price equal to the greater of (a) 100% of the principal amount of the Notes to be redeemed, and (b) as determined by the Quotation Agent, the sum of the present values of the remaining scheduled payments of principal and interest on the Notes to be redeemed (not including any portion of those payments of interest accrued as of the date of redemption) discounted to the date of redemption on a semi-annual basis (assuming 360-day years, each consisting of twelve 30-day months), at the Adjusted Treasury Rate plus 20 basis points, in the case of the 2009 Notes, and 25 basis points, in the case of the 2016 Notes plus, in each case, accrued interest to the date of redemption.

"Adjusted Treasury Rate" means, with respect to any date of redemption, the rate per annum equal to the semi-annual equivalent yield to maturity of the Comparable Treasury Issue, assuming a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for the date of redemption.

"Comparable Treasury Issue" means the United States Treasury security selected by the Quotation Agent as having a maturity comparable to the remaining term of the Notes to be redeemed that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of those Notes.

"Comparable Treasury Price" means, with respect to any date of redemption (a) the average of the Reference Treasury Dealer Quotations for the date of redemption, after excluding the highest and lowest Reference Treasury Dealer Quotations, or (b) if the trustee obtains fewer than four Reference Treasury Dealer Quotations, the average of all such Reference Treasury Dealer Quotations.

"Quotation Agent" means Banc of America Securities LLC or another Reference Treasury Dealer appointed by us.

"Reference Treasury Dealer" means (a) Banc of America Securities LLC and its successors; provided, however, that if the foregoing shall cease to be a primary U.S. Government securities dealer in the United States (a "Primary Treasury Dealer"), we shall substitute another Primary Treasury Dealer; and (b) any other Primary Treasury Dealer selected by us.

"Reference Treasury Dealer Quotations" means, with respect to each Reference Treasury Dealer and any date of redemption, the average, as determined by the trustee, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to the trustee by that Reference Treasury Dealer at 5:00 p.m., New York City time, on the third business day preceding that date of redemption.

Unless we default in payment of the redemption price, on and after the date of redemption, interest will cease to accrue on the Notes or portions thereof called for redemption.

On or before a redemption date, we will deposit with a paying agent (or with the trustee) sufficient money to pay the redemption price and accrued interest on the Notes to be redeemed.

If less than all of the Notes are to be redeemed at any time, the trustee will select Notes (or any portion of Notes in integral multiples of $2,000) for redemption as follows:

- if the Notes are listed, in compliance with the requirements of the principal national securities exchange on which the Notes are listed; or

- if the Notes are not so listed or there are no such requirements, on a pro rata basis, by lot or by such method as the trustee shall deem fair and appropriate.

However, no Note with a principal amount of $2,000 or less will be redeemed in part. Notice of redemption will be mailed by first class mail at least 30 days but not more than 60 days before the redemption date to each holder of Notes to be redeemed at its registered address. If any Note is to be redeemed in part only, the notice of redemption that relates to that Note will state the portion of the principal amount of that Note to be redeemed.

Events of Default

Each of the following constitutes an "Event of Default" with respect to a series of Notes:

- default in payment when due of the principal of or any premium on any Note of that series at maturity, upon redemption or otherwise;

- default for 60 days in the payment when due of interest on any Note of that series;

- failure by us or, so long as the Notes are guaranteed by a subsidiary guarantor, by such subsidiary guarantor, for 30 days after receipt of notice from the trustee or the holders to comply with any other term, covenant or warranty in the Indenture or the Notes of that series (provided that notice need not be given, and an Event of Default will occur, 30 days after any breach of the covenants described under " Consolidation, Merger or Sale");

- default under any mortgage, indenture or instrument under which there may be issued or by which there may be secured or evidenced any debt for money borrowed of us or any of the Subsidiaries of Plains All American Pipeline (or the payment of which is guaranteed by Plains All American Pipeline or any of its Subsidiaries), whether such debt or guarantee now exists or is created after the Issue Date, if (a) that default (x) is caused by a failure to pay principal of or premium, if any, or interest on such debt prior to the expiration of any grace period provided in such debt (a "Payment' Default"), or (y) results in the acceleration of the maturity of such debt to a date prior to its originally stated maturity, and, (b) in each case described in clauses (x) or (y) above, the principal amount of any such debt, together with the principal amount of any other such debt under which there has been a Payment Default or the maturity of which has been so accelerated, aggregates $25 million or more; provided that if any such default is cured or waived or any such acceleration rescinded, or such debt is repaid, within a period of 30 days from the continuation of such default beyond the applicable grace period or the occurrence of such acceleration, as the case may be, such Event of Default and any consequential acceleration of the Notes shall be automatically rescinded, so long as such rescission does not conflict with any judgment or decree;

- specified events in bankruptcy, insolvency or reorganization of us or, so long as the Notes are guaranteed by a subsidiary guarantor, by such subsidiary guarantor;

- so long as the Notes are guaranteed by a subsidiary guarantor:

  - the guarantee by such subsidiary guarantor ceases to be in full force and effect, except as otherwise provided in the Indenture;

  - the guarantee by such subsidiary guarantor is declared null and void in a judicial proceeding; or

  - such subsidiary guarantor denies or disaffirms its obligations under the Indenture or its guarantee.

An Event of Default for a particular series of Notes will not necessarily constitute an Event of Default for the other series of Notes or for any other series of debt securities that may be issued under the Base Indenture. In the case of an Event of Default arising from certain events of bankruptcy, insolvency or reorganization involving us, but not any subsidiary guarantor, all outstanding Notes will become due and payable immediately without further action or notice. If any other Event of Default occurs and is continuing with respect to a series of Notes, the trustee or the holders of at least 25% in principal amount of the then outstanding Notes of that series may declare all the Notes of that series to be due and payable immediately.

Consolidation, Merger or Sale

We will not merge, amalgamate or consolidate with or into any other Person or sell, convey, lease, transfer or otherwise dispose of all or substantially all of our assets to any Person, whether in a single transaction or series of related transactions, except in accordance with the provisions of the partnership agreement of Plains All American Pipeline, and unless:

- we are the surviving Person in the case of a merger, or the surviving Person:

  - is a partnership, limited liability company or corporation organized under the laws of the United States, a state thereof or the District of Columbia, provided that PAA Finance Corp. may not merge, amalgamate or consolidate with or into another Person other than a corporation satisfying such requirement for so long as Plains All American Pipeline is not a corporation; and

  - expressly assumes, by supplemental indenture in form reasonably satisfactory to the trustee, the due and punctual payment of the principal of, premium, if any, and interest on all of the Notes, and the due and punctual performance or observance of all the other obligations under the Indenture to be performed or observed by us;

- immediately after giving effect to the transaction or series of transactions, no Default or Event of Default has occurred and is continuing;

- if we are not the surviving Person, then each subsidiary guarantor, unless such subsidiary guarantor is the Person with which we have consummated a transaction under this provision, shall have confirmed that its guarantee of the Notes shall continue to apply to the obligations under the Notes and the Indenture; and

we have delivered to the trustee an officers' certificate and opinion of counsel, each stating that the merger, amalgamation, consolidation, sale, conveyance, transfer, lease or other disposition, and if a supplemental indenture is required, the supplemental indenture, comply with the Indenture and all other conditions precedent to the transaction have been complied with.

Thereafter, the surviving Person will be substituted for us under the Indenture. If we sell or otherwise dispose of (except by lease) all or substantially all of our assets and the above stated requirements are satisfied, we will be released from all our liabilities and obligations under the Indenture. If we lease all or substantially all of our assets, we will not be so released from our obligations under the Indenture.

Modification of the Indenture

Generally, we, the subsidiary guarantors and the trustee may amend or supplement the Indenture, the guarantees and the Notes with the written consent of the holders of at least a majority in principal amount of the then outstanding Notes of the affected series. However, without the consent of each holder affected, an amendment, supplement or waiver may not (with respect to any Notes held by a nonconsenting holder):

- reduce the principal amount of Notes whose holders must consent to an amendment, supplement or waiver;
- reduce the principal of or change the fixed maturity of any Note;
- reduce or waive the premium payable upon redemption or alter or waive the provisions with respect to the redemption of any Notes;
- reduce the rate of or change the time for payment of interest on any Note;
- waive a Default or an Event of Default in the payment of principal of or premium, if any, or interest on, any Notes (except a rescission of acceleration of the Notes with respect to either series by the holders of at least a majority in aggregate principal amount of that series and a waiver of the payment default that resulted from such acceleration);
- release any security that may have been granted with respect to the Notes;
- make any Note payable in currency other than that stated in the Notes;
- make any change in the provisions of the Indenture relating to waivers of past Defaults or the rights of holders of Notes to receive payments of principal of or premium, if any, or interest on the Notes;
- waive a redemption payment with respect to any Note;
- except as otherwise permitted in the Indenture, release any subsidiary guarantor from its obligations under its guarantee or the Indenture or change any guarantee in any manner that would adversely affect the rights of holders; or
- make any change in the preceding amendment, supplement and waiver provisions (except to increase any percentage set forth therein).

Notwithstanding the preceding, without the consent of any holder of Notes, we, the subsidiary guarantors and the trustee may amend or supplement the Indenture or the Notes:

- to cure any ambiguity, defect or inconsistency;
- to provide for uncertificated Notes in addition to or in place of certificated Notes;
- to provide for the assumption of our or a subsidiary guarantor's obligations to holders of Notes in the case of a merger or consolidation or sale of all or substantially all of our or such subsidiary guarantor's assets;
- to add or release subsidiary guarantors as permitted pursuant to the terms of a supplemental indenture (please read " The Guarantees");
- to make any changes that would provide any additional rights or benefits to the holders of Notes that do not, taken as a whole, adversely affect the rights under the Indenture of any holder of the Notes;
- to comply with requirements of the SEC in order to effect or maintain the qualification of the Indenture under the Trust Indenture Act;
- to evidence or provide for the acceptance of appointment under the Indenture of a successor trustee;
- to add any additional Events of Default;
- to secure the Notes and/or the guarantees; or
- to establish the form or terms of any other series of debt securities under the Base Indenture.

Covenants

Limitations on Liens

We will not, nor will we permit any Subsidiary to, create, assume, incur or suffer to exist any lien upon any Principal Property or upon any Capital Interests of any Restricted Subsidiary, whether owned or leased or hereafter acquired, to secure any of our debt or any debt of any other Person (other than debt securities issued under the Indenture), without in any such case making effective provision whereby all of the Notes shall be secured equally and ratably with, or prior to, such debt so long as such debt shall be so secured. The following are excluded from this restriction:

- Permitted Liens;
- any lien upon any property or assets created at the time of acquisition of such property or assets by us or any Restricted Subsidiary or within one year after such time to secure all or a portion of the purchase price for such property or assets or debt incurred to finance such purchase price, whether such debt was incurred prior to, at the time of or within one year after the date of such acquisition;
- any lien upon any property or assets to secure all or part of the cost of construction, development, repair or improvements thereon or to secure debt incurred prior to, at the time of, or within one year after completion of such construction, development, repair or improvements or the commencement of full operations thereof (whichever is later), to provide funds

for any such purpose;

any lien upon any property or assets existing thereon at the time of the acquisition thereof by us or any Restricted Subsidiary (whether or not the obligations secured thereby are assumed by us or any Restricted Subsidiary); provided, however, that such lien only encumbers the property or assets so acquired;

any lien upon any property or assets of a Person existing thereon at the time such Person becomes a Restricted Subsidiary by acquisition, merger or otherwise; provided, however, that such lien only encumbers the property or assets of such Person at the time such Person becomes a Restricted Subsidiary;

any lien upon any of our property or assets or the property or assets of any Restricted Subsidiary in existence on December 10, 2003 or provided for pursuant to agreements existing on December 10, 2003;

liens imposed by law or order as a result of any proceeding before any court or regulatory body that is being contested in good faith, and liens which secure a judgment or other court-ordered award or settlement as to which we or the applicable Restricted Subsidiary has not exhausted its appellate rights;

any extension, renewal, refinancing, refunding or replacement, or successive extensions, renewals, refinancings, refundings or replacements of liens, in whole or in part, referred to above; provided, however, that any such extension, renewal, refinancing, refunding or replacement lien shall be limited to the property or assets covered by the lien extended, renewed, refinanced, refunded or replaced and that the obligations secured by any such extension, renewal, refinancing, refunding or replacement lien shall be in an amount not greater than the amount of the obligations secured by the lien extended, renewed, refinanced, refunded or replaced and any of our expenses and the expenses of the Restricted Subsidiaries (including any premium) incurred in connection with such extension, renewal, refinancing, refunding or replacement; or

any lien resulting from the deposit of moneys or evidence of indebtedness in trust for the purpose of defeasing our debt or debt of any Restricted Subsidiary.

Notwithstanding the preceding, we may, and may permit any Restricted Subsidiary to, create, assume, incur, or suffer to exist any lien upon any Principal Property or Capital Interests of a Restricted Subsidiary to secure our debt or debt of any Person (other than debt securities issued under the Indenture), that is not excepted above without securing the Notes, provided that the aggregate principal amount of all debt then outstanding secured by such lien and all other liens not excepted above, together with all Attributable Indebtedness from Sale-leaseback Transactions, excluding Sale-leaseback Transactions permitted under " Limitations on Sale-Leasebacks," does not exceed 10% of Consolidated Net Tangible Assets.

Limitations on Sale-Leasebacks

We will not, and will not permit any Subsidiary to, engage in a Sale-leaseback Transaction, unless:

such Sale-leaseback Transaction occurs within one year from the date of completion of the acquisition of the Principal Property subject thereto or the date of the completion of construction, development or substantial repair or improvement, or commencement of full operations on such Principal Property, whichever is later;

the Sale-leaseback Transaction involves a lease for a period, including renewals, of not more than three years;

the Attributable Indebtedness from that Sale-leaseback Transaction is an amount equal to or less than the amount that we or such Subsidiary would be allowed to incur as debt secured by a lien on the Principal Property subject thereto without equally and ratably securing the Notes; or

we or such Subsidiary, within a one-year period after such Sale-leaseback Transaction, applies or causes to be applied an amount not less than the net sale proceeds from such Sale-leaseback Transaction to (A) the prepayment, repayment, redemption, reduction or retirement of any Pari Passu Debt of us or any Subsidiary, or (B) the expenditure or expenditures for Principal

Property used or to be used in the ordinary course of the business of Plains All American Pipeline or that of its Subsidiaries.

Notwithstanding the preceding, we may, and may permit any Subsidiary of Plains All American Pipeline to, effect any Sale-leaseback Transaction that is not excepted above, provided that the Attributable Indebtedness from such Sale-leaseback Transaction, together with the aggregate principal amount of then outstanding debt (other than debt securities issued under the Indenture) secured by liens upon Principal Properties not excepted in " Limitations on Liens," do not exceed 10% of Consolidated Net Tangible Assets.

SEC Reports

Regardless of whether Plains All American Pipeline is required to remain subject to the reporting requirements of Section 13 or 15(d) of the Exchange Act, it will electronically file with the SEC, so long as either series of Notes is outstanding, the annual, quarterly and other periodic reports that it is required to file (or would otherwise be required to file) with the SEC pursuant to Sections 13 and 15(d) of the Exchange Act, and such documents will be filed with the SEC on or prior to the respective dates (the "Required Filing Dates") by which it is required to file (or would otherwise be required to file) such documents, unless, in each case, such filings are not then permitted by the SEC.

If such filings are not then permitted by the SEC, or such filings are not generally available on the Internet free of charge, we will provide the trustee with, and the trustee will mail to any holder of Notes requesting in writing to the trustee copies of, such annual, quarterly and other periodic reports specified in Sections 13 and 15(d) of the Exchange Act within 15 days after its Required Filing Date.

In addition, we will furnish to the holders of Notes and to prospective investors, upon the requests of holders of Notes, any information required to be delivered pursuant to Rule 144A(d)(4) under the Securities Act, so long as the Notes are not freely transferable under the Securities Act.

Defeasance and Discharge

We may choose to either discharge our obligations under the Notes of either series in a legal defeasance, or to release ourselves from our covenant restrictions applicable to the Notes of either series in a covenant defeasance. We may do so at any time (provided certain other conditions contained in the Indenture are met) after we deposit with the trustee sufficient cash or government securities to pay the principal, interest, premium, if any, and any other sums due to the stated maturity date or redemption date of the Notes of the relevant series.

If we choose the legal defeasance option, the holders of Notes of the relevant series will not be entitled to the benefits of the Indenture except for registration of transfer and exchange of Notes, replacement of lost, stolen, destroyed or mutilated Notes, receipt of principal and interest on the original stated due dates and other specified provisions in the Indenture.

We may discharge our obligations under the Indenture or release ourselves from covenant restrictions only if, in addition to making the deposit with the trustee, we meet some specific requirements. Among other things:

- we must deliver an opinion of our legal counsel that the discharge or release will not result in holders having to recognize income, gain or loss for federal income tax purposes. In the case of legal defeasance, this opinion must be based on either an IRS letter ruling or change in federal tax law;

- we may not have a Default or Event of Default on the Notes discharged on the date of deposit or, insofar as Events of Default from bankruptcy or insolvency events are concerned, at any time in the period ending on the 91st day after the date of deposit; and the discharge may not violate any of our agreements other than the Notes of the relevant series and the Indenture.

Concerning the Trustee

Wachovia Bank, National Association, acts as indenture trustee, security registrar and paying agent with respect to the Notes. The trustee makes no representation or warranty, express or implied, as to the accuracy or completeness of any information contained in this prospectus, except for such information that specifically pertains to the trustee.

Governing Law

The Indenture and the Notes are governed by and will be construed in accordance with the law of the State of New York.

Definitions

"Attributable Indebtedness," when used with respect to any Sale-leaseback Transaction, means, as at the time of determination, the present value, discounted at the rate set forth or implicit in the terms of the lease included in such transaction, of the total obligations of the lessee for rental payments, other than amounts required to be paid on account of property taxes, maintenance, repairs, insurance, assessments, utilities, operating and labor costs and other items that do not constitute payments for property rights during the remaining term of the lease included in such Sale-leaseback Transaction including any period for which such lease has been extended. In the case of any lease that is terminable by the lessee upon the payment of a penalty or other termination payment, such amount shall be the lesser of the amount determined assuming termination upon the first date such lease may be terminated, in which case the amount shall also include the amount of the penalty or termination payment, but no rent shall be considered as required to be paid under such lease subsequent to the first date upon which it may be so terminated, or the amount determined assuming no such termination.

"Board of Directors" means (a) with respect to Plains All American Pipeline, the board of directors of the Managing General Partner, and (b) with respect to PAA Finance Corp., its board of directors or, in each case, with respect to any determination or resolution permitted to be made under the Indenture, any authorized committee or subcommittee of such board.

"Capital Interests" means any and all shares, interests, participations, rights or other equivalents (however designated) of capital stock, including, without limitation, with respect to partnerships, partnership interests (whether general or limited) and any other interest or participation that confers on a Person the right to receive a share of the profits and losses of, or distributions of assets of, such Person.

"Consolidated Net Tangible Assets" means, at any date of determination, the total amount of assets after deducting therefrom:

(1) all current liabilities excluding:

(a) any current liabilities that by their terms are extendible or renewable at the option of the obligor thereon to a time more than 12 months after the time as of which the amount thereof is being computed; and

(b) current maturities of long-term debt; and

(2) the amount, net of any applicable reserves, of all goodwill, trade names, trademarks, patents and other like intangible assets,

all as set forth on the consolidated balance sheet of Plains All American Pipeline for its most recently completed fiscal quarter, prepared in accordance with generally accepted accounting principles.

"Exchange Act" means the Securities Exchange Act of 1934, as amended.

"Funded Debt" means all debt maturing one year or more from the date of the creation thereof, all debt directly or indirectly renewable or extendible, at the option of the debtor, by its terms or by the terms of any instrument or agreement relating thereto, to a date one year or more from the date of the creation thereof, and all debt under a revolving credit or similar agreement obligating the lender or lenders to extend credit over a period of one year or more.

"Issue Date" means with respect to the Notes, the date on which the Notes are initially issued.

"Managing General Partner" means Plains All American GP LLC, a Delaware limited liability company, and its successors and permitted assigns, as general partner of Plains AAP, L.P., a Delaware limited partnership (and its successors and permitted assigns, as general partner of Plains All American Pipeline) or as the business entity with the ultimate authority to manage the business and operations of Plains All American Pipeline.

"Pari Passu Debt" means any of our Funded Debt, whether outstanding on the Issue Date or thereafter created, incurred or assumed, unless, in the case of any particular Funded Debt, the instrument creating or evidencing the same or pursuant to which the same is outstanding expressly provides that such Funded Debt shall be subordinated in right of payment to the Notes.

"Permitted Liens" means:

(1) liens upon rights-of-way for pipeline purposes;

(2) any statutory or governmental lien or lien arising by operation of law, or any mechanics', repairmen's, materialmen's, suppliers', carriers', landlords', warehousemen's or similar lien incurred in the ordinary course of business which is not yet due or which is being contested in good faith by appropriate proceedings and any undetermined lien which is incidental to construction, development, improvement or repair;

(3) the right reserved to, or vested in, any municipality or public authority by the terms of any right, power, franchise, grant, license, permit or by any provision of law, to purchase or recapture or to designate a purchaser of any property;

(4) liens of taxes and assessments which are:

  (a) for the then current year,

  (b) not at the time delinquent, or

  (c) delinquent but the validity of which is being contested at the time by us or any Restricted Subsidiary in good faith;

(5) liens of, or to secure performance of, leases, other than capital leases;

(6) any lien upon, or deposits of, any assets in favor of any surety company or clerk of court for the purpose of obtaining indemnity or stay of judicial proceedings;

(7) any lien upon property or assets acquired or sold by us or any Restricted Subsidiary resulting from the exercise of any rights arising out of defaults on receivables;

(8)

any lien incurred in the ordinary course of business in connection with worker's compensation, unemployment insurance, temporary disability, social security, retiree health or similar laws or regulations or to secure obligations imposed by statute or governmental regulations;

(9) any lien in favor of us or any Restricted Subsidiary;

(10) any lien in favor of the United States of America or any state thereof, or any department, agency or instrumentality or political subdivision of the United States of America or any state thereof, to secure partial, progress, advance, or other payments pursuant to any contract or statute, or any debt incurred by us or any Restricted Subsidiary for the purpose of financing all or any part of the purchase price of, or the cost of constructing, developing, repairing or improving, the property or assets subject to such lien;

(11) any lien securing industrial development, pollution control or similar revenue bonds;

(12) any lien securing our debt or debt of any Restricted Subsidiary, all or a portion of the net proceeds of which are used, substantially concurrently with the funding thereof (and for purposes of determining such "substantial concurrence," taking into consideration, among other things, required notices to be given to holders of outstanding securities under the Indenture (including the Notes) in connection with such refunding, refinancing or repurchase, and the required corresponding durations thereof), to refinance, refund or repurchase all outstanding securities under the Indenture (including the Notes), including the amount of all accrued interest thereon and reasonable fees and expenses and premium, if any, incurred by us or any Restricted Subsidiary in connection therewith;

(13) liens in favor of any Person to secure obligations under the provisions of any letters of credit, bank guarantees, bonds or surety obligations required or requested by any governmental authority in connection with any contract or statute;

(14) any lien upon or deposits of any assets to secure performance of bids, trade contracts, leases or statutory obligations;

(15) any lien or privilege vested in any grantor, lessor or licensor or permittor for rent or other charges due or for any other obligations or acts to be performed, the payment of which rent or other charges or performance of which other obligations or acts is required under leases, easements, rights-of-way, leases, licenses, franchises, privileges, grants or permits, so long as payment of such rent or the performance of such other obligations or acts is not delinquent or the requirement for such payment or performance is being contested in good faith by appropriate proceedings;

(16) easements, exceptions or reservations in any property of Plains All American Pipeline or any property of any of its Restricted Subsidiaries granted or reserved for the purpose of pipelines, roads, the removal of oil, gas, coal or other minerals, and other like purposes for the joint or common use of real property, facilities and equipment, which are incidental to, and do not materially interfere with, the ordinary conduct of its business or the business of Plains All American Pipeline and its Subsidiaries, taken as a whole;

(17) liens arising under operating agreements, joint venture agreements, partnership agreements, oil and gas leases, farmout agreements, division orders, contracts for sale, transportation or exchange of oil and natural gas, unitization and pooling declarations and agreements, area of mutual interest agreements and other agreements arising in the ordinary course of Plains All American Pipeline's or any Restricted Subsidiary's business that are customary in the business of marketing, transportation and terminalling of crude oil and/or marketing of liquefied petroleum gas; or

(18) any obligations or duties to any municipality or public authority with respect to any lease, easement, right-of-way, license, franchise, privilege, permit or grant.

"Person" means any individual, corporation, partnership, joint venture, limited liability company, association, joint-stock company, trust, other entity, unincorporated organization or government or any agency or political subdivision thereof.

"Principal Property" means, whether owned or leased on the Issue Date or thereafter acquired:

(1) any of the pipeline assets of Plains All American Pipeline or the pipeline assets of any Subsidiary of Plains All American Pipeline, including any related facilities employed in the transportation, distribution, terminalling, gathering, treating, processing, marketing or storage of crude oil or refined petroleum products, natural gas, natural gas liquids, fuel additives or petrochemicals; and

(2) any processing or manufacturing plant or terminal owned or leased by Plains All American Pipeline or any Subsidiary of Plains All American Pipeline; except, in either case above:

(a) any such assets consisting of inventories, furniture, office fixtures and equipment, including data processing equipment, vehicles and equipment used on, or useful with, vehicles, and

(b) any such assets, plant or terminal which, in the good faith opinion of the Board of Directors, is not material in relation to the activities of Plains All American Pipeline or the activities of Plains All American Pipeline and its Subsidiaries, taken as a whole.

"Restricted Subsidiary" means any Subsidiary of Plains All American Pipeline owning or leasing, directly or indirectly through ownership in another Subsidiary, any Principal Property.

"Sale-leaseback Transaction" means the sale or transfer by us or any Subsidiary of Plains All American Pipeline of any Principal Property to a Person (other than us or a Subsidiary of Plains All American Pipeline) and the taking back by us or any Subsidiary of Plains All American Pipeline, as the case may be, of a lease of such Principal Property.

"Securities Act" means the Securities Act of 1933, as amended.

"Subsidiary" means, with respect to any Person:

(1) any other Person of which more than 50% of the total voting power of shares or other Capital Interests entitled, without regard to the occurrence of any contingency, to vote in the election of directors, managers or trustees (or equivalent persons) thereof is at the time owned or controlled, directly or indirectly, by such Person or one or more of the other Subsidiaries of such Person or a combination thereof; or

(2) in the case of a partnership, more than 50% of the partners' Capital Interests, considering all partners' Capital Interests as a single class, is at the time owned or controlled, directly or indirectly, by such Person or one or more of the other Subsidiaries of such Person or a combination thereof.

TAX CONSIDERATIONS

The following discussion is a summary of certain federal income tax considerations relevant to the exchange of outstanding Notes for new Notes, but does not purport to be a complete analysis of all potential tax effects. The discussion is based upon the Internal Revenue Code of 1986, as amended, Treasury Regulations, Internal Revenue Service rulings and pronouncements and judicial decisions now in effect, all of which may be subject to change at any time by legislative, judicial or administrative action. These changes may be applied retroactively in a manner that could adversely affect a holder of new Notes. The description does not consider the effect of any applicable foreign, state, local or other tax laws or estate or gift tax considerations.

We believe that the exchange of outstanding Notes for new Notes should not be an exchange or otherwise a taxable event to a holder for United States federal income tax purposes. Accordingly, a holder should have the same adjusted issue price, adjusted basis and holding period in the new Notes as it had in the outstanding Notes immediately before the exchange.

PLAN OF DISTRIBUTION

Based on interpretations by the staff of the SEC in no action letters issued to third parties, we believe that you may transfer new Notes issued under either exchange offer in exchange for the outstanding Notes if:

- you acquire the new Notes in the ordinary course of your business; and
- you are not engaged in, and do not intend to engage in, and have no arrangement or understanding with any person to participate in, a distribution of such new Notes.

You may not participate in either exchange offer if you are:

- our "affiliate" within the meaning of Rule 405 under the Securities Act; or
- a broker-dealer that acquired outstanding Notes directly from us.

Each broker-dealer that receives new Notes for its own account pursuant to either exchange offer must acknowledge that it will deliver a prospectus in connection with any resale of such new Notes. To date, the staff of the SEC has taken the position that broker-dealers may fulfill their prospectus delivery requirements with respect to transactions involving an exchange of securities such as these exchange offers, other than a resale of an unsold allotment from the original sale of the outstanding Notes, with the prospectus contained in this registration statement. This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of new Notes received in exchange for outstanding Notes where such outstanding Notes were acquired as a result of market-making activities or other trading activities. We have agreed that, for a period of up to one year after the consummation of the exchange offers, we will make this prospectus, as amended or supplemented, promptly available to any broker-dealer for use in connection with any such resale.

If you wish to exchange your outstanding Notes for new Notes in the applicable exchange offer, you will be required to make representations to us as described in "Exchange Offers Purpose and Effect of the Exchange Offers" and " Procedures for Tendering Your Representations to Us" in this prospectus and in the applicable letter of transmittal. In addition, if you are a broker-dealer who receives new Notes for your own account in exchange for outstanding Notes that were acquired by you as a result of market-making activities or other trading activities, you will be required to acknowledge that you will deliver a prospectus in connection with any resale by you of such new Notes.

We will not receive any proceeds from any sale of new Notes by broker-dealers. New Notes received by broker-dealers for their own account pursuant to the applicable exchange offer may be sold from time to time in one or more transactions:

- in the over-the-counter market;
- in negotiated transactions;
- through the writing of options on the new Notes or a combination of the preceding methods of resale;
- at market prices prevailing at the time of resale; and
- at prices related to such prevailing market prices or negotiated prices.

Any such resale may be made directly to purchasers or to or through brokers or dealers who may receive compensation in the form of commissions or concessions from any such broker-dealer or the purchasers of any such new Notes. Any broker-dealer that resells new Notes that were received by it for its own account pursuant to the exchange offers and any broker or dealer that participates in a distribution of such new Notes may be deemed to be an "underwriter" within the meaning of the Securities Act and any profit from any such resale of new notes and any commissions or concessions received by any such persons may be deemed to be underwriting compensation under the Securities Act. Each letter of transmittal states that by acknowledging that it will deliver and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an "underwriter" within the meaning of the Securities Act.

For a period of one year after the consummation of each exchange offer, we will promptly send additional copies of this prospectus and any amendment or supplement to this prospectus to any broker-dealer that requests such documents in a letter of transmittal. We have agreed to pay all expenses incident to each exchange offer (including the expenses of one counsel for the holders of the outstanding Notes) other than commissions or concessions of any broker-dealers and will indemnify the holders of the outstanding Notes (including any broker-dealers) against certain liabilities, including liabilities under the Securities Act.

VALIDITY OF THE NEW NOTES

The validity of the new Notes will be passed upon for us by Vinson & Elkins L.L.P., Houston, Texas.

EXPERTS

The consolidated financial statements of Plains All American Pipeline, L.P. as of December 31, 2003 and 2002 and for each of the three years in the period ended December 31, 2003 and the balance sheet of Plains AAP, L.P. as of December 31, 2003 included in this Prospectus have been so included in reliance on the reports of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

The combined financial statements of the Capline Pipe Line Business, Capwood Pipe Line Business and Patoka Pipe Line Business (the "Businesses") as of December 31, 2003 and 2002 and for the year ended December 31, 2003 and for the periods from February 14, 2002 through December 31, 2002 and January 1, 2002 through February 13, 2002 included in this Prospectus have been so included in reliance on the report (which report contains an explanatory paragraph relating to the Businesses being sold to Plains All American Pipeline, L.P. as described in Note 6 to the combined financial statements) of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

The consolidated financial statements of Link Energy LLC and its subsidiaries (Successor Company) at December 31, 2003 and for the period from March 1, 2003 to December 31, 2003 and of EOTT Energy Partners, L.P. and its subsidiaries (Predecessor Company) at December 31, 2002 and for the period from January 1, 2003 to February 28, 2003 and for each of the two years in the period ended December 31, 2002 included in this Prospectus have been so included in reliance on the reports (which contain an explanatory paragraph relating to the Successor Company's and Predecessor Company's ability to continue as a going concern as described in Note 3 to the consolidated financial statements, an explanatory paragraph relating to the adoption of fresh start accounting as described in Note 1 to the consolidated financial statements and an explanatory paragraph relating to the restatement of the financial results as described in Notes 1 and 10 to the consolidated financial statements) of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

WHERE YOU CAN FIND MORE INFORMATION

We file annual, quarterly and special reports and other information with the Securities and Exchange Commission under the Securities Exchange Act of 1934. You can inspect and/or copy these reports and other information at offices maintained by the SEC, including:

- the principal offices of the SEC located at Judiciary Plaza, 450 Fifth Street, N.W., Room 1024, Washington, D.C. 20549;
- the SEC's website at http://www.sec.gov.

In addition, please call the SEC at 1-800-732-0330 for further information on their public reference room.

Further, our common units are listed on the New York Stock Exchange, and you can inspect similar information at the offices of the New York Stock Exchange, located at 20 Broad Street, New York, New York 10005.

You can read and copy any of our materials filed with the SEC at our website at http://www.paalp.com or you may request a copy of these filings at no cost by making written or telephone requests for copies to:

Plains All American Pipeline, L.P.
333 Clay Street, Suite 1600
Houston, Texas 77002
Attention: Tim Moore
Telephone: (713) 646-4100

We intend to furnish or make available to our unitholders within 75 days following the close of our fiscal year end annual reports containing audited financial statements prepared in accordance with generally accepted accounting principles and furnish or make available within 40 days following the close of each fiscal quarter quarterly reports containing unaudited interim financial information, including the information required by Form 10-Q, for the first three fiscal quarters of each of our fiscal years. Our annual report will include a description of any transactions with the general partner or its affiliates, and of fees, commissions, compensation and other benefits paid, or accrued to the general partner or its affiliates for the fiscal year completed, including the amount paid or accrued to each recipient and the services performed.

You should rely only on the information provided in this prospectus. The information contained on our website is not a part of this prospectus. We have not authorized anyone else to provide you with any information. You should not assume that the information provided in this prospectus is accurate as of any date other than the date on the cover of this prospectus.

FORWARD-LOOKING STATEMENTS

All statements, other than statements of historical fact, included in this prospectus are forward looking statements, including, but not limited to, statements identified by the words "anticipate," "believe," "estimate," "expect," "plan," "intend" and "forecast," and similar expressions and statements regarding our business strategy, plans and objectives for future operations. These statements reflect our current views with respect to future events, based on what we believe are reasonable assumptions. Certain factors could cause actual results to differ materially from results anticipated in the forward looking statements. These factors include, but are not limited to:

- abrupt or severe production declines or production interruptions in outer continental shelf production located offshore California and transported on our pipeline system;
- the success of our risk management activities;
- the availability of, and our ability to consummate, acquisition or combination opportunities;
- our access to capital to fund additional acquisitions and our ability to obtain debt or equity financing on satisfactory terms;
- successful integration and future performance of acquired assets or businesses;
- environmental liabilities that are not covered by an indemnity, insurance or existing reserves;
- maintenance of our credit rating and ability to receive open credit from our suppliers;
- declines in volumes shipped on the Basin Pipeline and our other pipelines by third party shippers;
- the availability of adequate third party production volumes for transportation and marketing in the areas in which we operate;
- successful third party drilling efforts in areas in which we operate pipelines or gather crude oil;
- demand for various grades of crude oil and resulting changes in pricing conditions or transmission throughput requirements;
- fluctuations in refinery capacity in areas supplied by our transmission lines;
- the effects of competition;
- continued creditworthiness of, and performance by, counter parties;
- the impact of crude oil price fluctuations;
- the impact of current and future laws and governmental regulations;

- shortages or cost increases of power supplies, materials or labor;
- weather interference with business operations or project construction;
- the currency exchange rate of the Canadian dollar;
- fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our Long-Term Incentive Plan; and
- general economic, market or business conditions.

Other factors described herein, or factors that are unknown or unpredictable, could also have a material adverse effect on future results. Please read "Risk Factors" beginning on page 6 of this prospectus. Except as required by securities laws, we do not intend to update these forward looking statements and information.

INDEX TO FINANCIAL STATEMENTS

LINK ENERGY LLC

UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS:

LINK ENERGY LLC

CONSOLIDATED FINANCIAL STATEMENTS:

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

Plains All American Pipeline, L.P. ("PAA") is a publicly traded Delaware limited partnership engaged in interstate and intrastate crude oil transportation, and crude oil gathering, marketing, terminalling and storage, as well as the marketing and storage of liquefied petroleum gas and other petroleum products. The following unaudited pro forma financial statements are presented to give effect to the transactions described below:

The acquisition of the North American crude oil and pipeline operations of Link Energy LLC, ("Link Energy" and the "Link acquisition"). The acquisition price of approximately $332 million includes the assumption of liabilities and net working capital items and transaction and other acquisition costs. The acquisition closed and was effective on April 1, 2004 and has been accounted for using the purchase method of accounting.

The acquisition of Shell Pipeline Company LP's ("SPLC") interest in certain entities. The principal assets of the entities include interests in the Capline Pipe Line System, the Capwood Pipe Line System and the Patoka Pipe Line System (referred to in this report as "the SPLC acquisition"). The purchase price, including transaction and closing costs, was approximately $158.5 million. The acquisition closed and was effective on March 1, 2004. The acquisition has been accounted for using the purchase method of accounting.

The transactions described above are included in PAA's historical unaudited consolidated balance sheet as of September 30, 2004. Accordingly, a pro forma balance sheet is not presented. The unaudited pro forma statements of operations for the nine months ended September 30, 2004 and the year ended December 31, 2003 are based upon the following:

1) the historical consolidated statements of operations of PAA for the nine months ended September 30, 2004 and the year ended December 31, 2003;

2) the historical consolidated statements of operations of Link Energy for the three months ended March 31, 2004 and the year ended December 31, 2003; and

3) the historical combined statements of operations for the businesses acquired in the SPLC acquisition for the two months ended February 29, 2004 and the year ended December 31, 2003.

The unaudited pro forma combined statements of operations are not necessarily indicative of the results of the actual or future operations that would have been achieved had the transactions occurred at the dates assumed (as noted below). The unaudited pro forma combined statements of operations should be read in conjunction with: i) the notes thereto; ii) the historical unaudited financial statements of PAA for the nine months ended September 30, 2004; iii) the historical unaudited financial statements of Link Energy for the three months ended March 31, 2004; and iv) the audited financial statements of PAA for the year ended December 31, 2003, as well as those for Link Energy and the businesses acquired in the SPLC acquisition, for the same period.

The following unaudited pro forma combined statements of operations for the nine months ended September 30, 2004 and the year ended December 31, 2003 have been prepared as if the transactions described above had taken place at the beginning of the period presented.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
UNAUDITED PRO FORMA COMBINED STATEMENT OF OPERATIONS
For the Nine Months Ended September 30, 2004
(in thousands, except per unit data)

	Plains All American Historical	Link Energy Historical	SPLC Acquisition Historical	Pro Forma Acquisition Adjustments	Plains All American Pro Forma
REVENUES	$ 14,803,384	$ 40,682	$ 7,416	$ (465)(a)	$ 14,851,017
COSTS AND EXPENSES					
Purchases and related costs	14,400,426	8,081		(465)(a)	14,408,042
Field operating costs (excluding LTIP charge)	158,053	20,725	2,023		180,801
LTIP charge operations	567				567
General and administrative expenses (excluding LTIP charge)	54,565	18,514			73,079
LTIP charge general and administrative	3,661				3,661
Depreciation and amortization	45,887	5,060	874	(5,934)(b) 2,571 (c)	48,458
Total costs and expenses	14,663,159	52,380	2,897	(3,828)	14,714,608
Other, net		(20)			(20)
Gains on sales of assets	643	730(e)			1,373
OPERATING INCOME	140,868	(10,988)	4,519	3,363	137,762
OTHER INCOME/(EXPENSE)					
Interest expense	(32,201)	(11,531)		(2,893)(d)	(46,625)
Interest and other income (expense), net	(250)	(24)			(274)
Income from continuing operations before cumulative effect of change in accounting principle	108,417	(22,543)	4,519	470	90,863
Cumulative effect of change in accounting principle	(3,130)				(3,130)
NET INCOME (LOSS) FROM CONTINUING OPERATIONS	$ 105,287	$ (22,543)	$ 4,519	$ 470	$ 87,733
NET INCOME FROM CONTINUING OPERATIONS LIMITED PARTNERS	$ 97,692				$ 80,489
NET INCOME FROM CONTINUING OPERATIONS GENERAL PARTNER	$ 7,595				$ 7,244
BASIC AND DILUTED NET INCOME FROM CONTINUING OPERATIONS PER LIMITED PARTNER UNIT					
Income from continuing operations before cumulative effect of change in accounting principle	$ 1.63				$ 1.35
Cumulative effect of change in accounting principle	(0.05)				(0.05)
Net income from continuing operations	$ 1.58				$ 1.30
BASIC AND DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	61,929				61,929

See notes to unaudited pro forma combined financial statements

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
UNAUDITED PRO FORMA COMBINED STATEMENT OF OPERATIONS
For the Twelve Months Ended December 31, 2003
(in thousands, except per unit data)

		Link Energy Historical				
		Successor Company	Predecessor Company			
	Plains All American Historical	Ten Months Ended December 31, 2003	Two Months Ended February 28, 2003	SPLC Acquisition Historical	Pro Forma Acquisition Adjustments	Plains All American Pro Forma
REVENUES	$ 12,589,849	$ 153,033	$ 31,635	$ 35,855	$ (2,828)(a)	$ 12,807,544
COSTS AND EXPENSES						
Purchases and related costs	12,232,536	23,863	4,521		(2,828)(a)	12,258,092
Field operating costs (excluding LTIP charge)	134,177	70,102	13,020	10,574		227,873
LTIP charge operations	5,727					5,727
General and administrative expenses (excluding LTIP charge)	49,969	45,959	6,846	1,275		104,049
LTIP charge general and administrative	23,063					23,063
Depreciation and amortization	46,821	17,161	4,642	5,264	(27,067)(b) 11,607 (c)	58,428
Total costs and expenses	12,492,293	157,085	29,029	17,113	(18,288)	12,677,232
Other, net		1,982	8			1,990
Gains on sales of assets	648	11,885(e)			(11,700)(f)	833
OPERATING INCOME	98,204	9,815	2,614	18,742	3,760	133,135
OTHER INCOME/(EXPENSE)						
Interest expense	(35,226)	(32,708)	(5,645)		(13,206)(d)	(86,785)
Interest and other income (expense), net	(3,530)	192	156			(3,182)
Income (Loss) from Continuing Operations Before Reorganization Items, Net Gain on Discharge of Debt and Fresh Start Adjustments	59,448	(22,701)	(2,875)	18,742	(9,446)	43,168
Reorganization Items			(7,330)			(7,330)
Net Gain on Discharge of Debt			131,560			131,560
Fresh Start Adjustments			(56,771)			(56,771)
NET INCOME (LOSS) FROM CONTINUING OPERATIONS	$ 59,448	$ (22,701)	$ 64,584	$ 18,742	$ (9,446)	$ 110,627
NET INCOME FROM CONTINUING OPERATIONS LIMITED PARTNERS	$ 53,473					$ 103,628
NET INCOME FROM CONTINUING OPERATIONS GENERAL PARTNER	$ 5,975					$ 6,999
BASIC NET INCOME FROM CONTINUING OPERATIONS PER	$ 1.01					$ 1.96

	Link Energy Historical	
LIMITED PARTNER UNIT		
DILUTED NET INCOME FROM CONTINUING OPERATIONS PER LIMITED PARTNER UNIT	$ 1.00	$ 1.94
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	52,743	52,743
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	53,400	53,400

See notes to unaudited pro forma combined financial statements

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
NOTES TO UNAUDITED PRO FORMA COMBINED FINANCIAL STATEMENTS

Note 1 Acquisitions

Link Acquisition

The Link acquisition presented in these pro forma statements has been accounted for using the purchase method of accounting and the purchase price has been allocated in accordance with Statement of Financial Accounting Standards No. 141, "Business Combinations." The acquisition consists of the North American crude oil and pipeline operations of Link Energy. The purchase price of approximately $332 million includes cash paid of approximately $268 million and approximately $64 million of net liabilities assumed and acquisition related costs. The acquisition closed and was effective on April 1, 2004. The total purchase price and the related allocation are preliminary as we are in the process of evaluating certain estimates. The purchase price allocation is set forth in the table below (in millions):

Fair value of assets acquired:	
Property and equipment	$ 262.3
Inventory	1.1
Linefill	48.4
Inventory in third party assets	15.1
Goodwill	5.0
Other long term assets	0.2
Subtotal	332.1
Accounts receivable	405.4
Other current assets	1.8
Subtotal	407.2
Total assets acquired	739.3
Fair value of liabilities assumed:	
Accounts payable and accrued liabilities	(455.4)
Other current liabilities	(8.5)
Other long-term liabilities	(7.4)
Total liabilities assumed	(471.3)
Cash paid for acquisition	$ 268.0(1)

(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.

SPLC Acquisition

The SPLC acquisition presented in these pro forma statements has been accounted for using the purchase method of accounting and the purchase price has been allocated in accordance with Statement of Financial Accounting Standards No. 141, "Business Combinations." The purchase consists of the acquisition of Shell Pipeline Company LP's ("SPLC") interest in certain entities. The principal assets of the entities include interests in certain businesses from Shell Pipeline Company, including its interests in the Capline Pipe Line System, the Capwood Pipe Line System and the Patoka Pipe Line System. The purchase price of approximately $158.5 million includes transaction and closing costs. The acquisition closed and was effective on March 1, 2004. The purchase price allocation is as follows (in millions):

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

Note 2 Pro Forma Adjustments

The pro forma adjustments are as follows:

a. Elimination of purchases and sales related to transactions between PAA and Link Energy.

b. Reversal of historical depreciation in the amounts of $5.1 million and $0.9 million in the nine-month period ended September 30, 2004 as recorded by Link Energy and SPLC for the three months and two months prior to acquisition, respectively and $21.8 million and $5.3 million for the year ended December 31, 2003 as recorded by Link Energy and SPLC, respectively.

c. Recording of depreciation based on the straight-line method over average useful lives ranging from 5 to 50 years in the amounts of $1.9 million and $0.7 million in the nine-month period ended September 30, 2004 for the assets acquired from Link Energy and SPLC for the three months and two months prior to acquisition, respectively and $7.6 million and $4.0 million for the year ended December 31, 2003 for the assets acquired from Link Energy and SPLC, respectively.

d. Adjustment to interest expense for the increase in long-term debt from draws on our revolving credit facilities to finance the acquisitions using an average interest rate of 3.1% for both periods presented. The increase in long-term debt of $268 million for the Link acquisition resulted in incremental interest expense on a pro forma basis of $2.1 million for the three months prior to acquisition in the nine-month period ended September 30, 2004 and $8.3 million for the year ended December 31, 2003. The increase in long-term debt of $158.5 million for the SPLC acquisition resulted in incremental interest expense on a pro forma basis of $0.8 million for the two months prior to acquisition in the nine-month period ended September 30, 2004 and $4.9 million for the year ended December 31, 2003. The impact to interest expense of a $^{1}/_{8}$% change in interest rates would be approximately $0.5 million per year.

e. Reclassification of gain on sale of assets from Other (Income) Expense as shown in Link Energy's historical financial statements to conform to PAA's presentation.

f. Elimination of the gain on sale of assets in October 2003 resulting from Link Energy's sale of the ArkLaTex assets to PAA, which is included in Link Energy's historical financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands, except unit data)

	September 30, 2004	December 31, 2003
	(unaudited)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 4,547	$ 4,137
Trade accounts receivable, net	846,347	590,645
Inventory	242,312	105,967
Other current assets	55,501	32,225
Total current assets	1,148,707	732,974
PROPERTY AND EQUIPMENT	1,824,314	1,272,634
Accumulated depreciation	(165,589)	(121,595)
	1,658,725	1,151,039
OTHER ASSETS		
Pipeline linefill in owned assets	159,985	95,928
Inventory in third party assets	46,359	26,725
Other, net	92,245	88,965
Total assets	$ 3,106,021	$ 2,095,631
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable	$ 965,265	$ 603,460
Due to related parties	33,447	26,981
Short-term debt	122,882	127,259
Other current liabilities	77,641	44,219
Total current liabilities	1,199,235	801,919
LONG-TERM LIABILITIES		
Long-term debt under credit facilities	40,408	70,000
Senior notes, net of unamortized discount of $2,820 and $1,009, respectively	797,180	448,991
Other long-term liabilities and deferred credits	24,780	27,994
Total liabilities	2,061,603	1,348,904
COMMITMENTS AND CONTINGENCIES (NOTE 10)		
PARTNERS' CAPITAL		
Common unitholders (62,740,218 and 49,502,556 units outstanding at September 30, 2004, and December 31, 2003, respectively)	895,479	744,073
Class B common unitholder (1,307,190 units outstanding at each date)	18,302	18,046
Class C common unitholders (3,245,700 units and no units outstanding at September 30, 2004, and December 31, 2003, respectively)	98,856	

	September 30, 2004	December 31, 2003
Subordinated unitholders (no units and 7,522,214 units outstanding at September 30, 2004, and December 31, 2003, respectively)		(39,913)
General partner	31,781	24,521
Total partners' capital	1,044,418	746,727
	$ 3,106,021	$ 2,095,631

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

	Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2003
	(unaudited)	
REVENUES		
Crude oil and LPG sales	$ 14,218,956	$ 8,572,569
Other gathering, marketing, terminalling and storage revenues	27,920	22,777
Pipeline margin activities revenues	424,165	376,660
Pipeline tariff activities revenues	132,343	72,768
Total revenues	14,803,384	9,044,774
COSTS AND EXPENSES		
Crude oil and LPG purchases and related costs	13,992,768	8,417,316
Pipeline margin activities purchases	407,658	362,250
Field operating costs (excluding LTIP charge)	158,053	100,301
LTIP charge operations	567	1,390
General and administrative expenses (excluding LTIP charge)	54,565	37,431
LTIP charge general and administrative	3,661	6,006
Depreciation and amortization	45,887	34,164
Total costs and expenses	14,663,159	8,958,858
Gains on sales of assets	643	608
OPERATING INCOME	140,868	86,524
OTHER INCOME/(EXPENSE)		
Interest expense (net of $207 and $461 capitalized for the nine month periods, respectively)	(32,201)	(26,480)
Interest income and other, net	(250)	(424)
Income before cumulative effect of change in accounting principle	108,417	59,620
Cumulative effect of change in accounting principle	(3,130)	
NET INCOME	$ 105,287	$ 59,620
NET INCOME-LIMITED PARTNERS	$ 97,692	$ 54,958
NET INCOME-GENERAL PARTNER	$ 7,595	$ 4,662
BASIC NET INCOME PER LIMITED PARTNER UNIT		
Income before cumulative effect of change in accounting principle	$ 1.63	$ 1.06
Cumulative effect of change in accounting principle	(0.05)	
Basic net income per limited partner unit	$ 1.58	$ 1.06

	Nine Months Ended September 30,	
DILUTED NET INCOME PER LIMITED PARTNER UNIT		
Income before cumulative effect of change in accounting principle	$ 1.63	$ 1.05
Cumulative effect of change in accounting principle	(0.05)	
Diluted net income per limited partner unit	$ 1.58	$ 1.05
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	61,929	51,735
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	61,929	52,407

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2003
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 105,287	$ 59,620
Adjustments to reconcile to cash flows from operating activities:		
Depreciation and amortization	45,887	34,164
Cumulative effect of accounting change	3,130	
Change in derivative fair value	(1,431)	1,731
Noncash portion of LTIP charge	4,228	3,700
Gain on foreign currency revaluation	(3,423)	
Noncash amortization of terminated interest rate swap	1,092	
Loss on refinancing of debt	658	
Gain on sale of assets	(643)	(608)
Net cash paid for terminated swaps	(1,465)	
Changes in assets and liabilities, net of acquisitions:		
Trade accounts receivable and other	(285,123)	132,366
Inventory	(127,391)	(84,690)
Accounts payable and other current liabilities	365,784	84,717
Settlement of environmental indemnities		4,600
Due to related parties	6,461	500
Net cash provided by operating activities	113,051	236,100
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions	(495,715)	(99,897)
Additions to property and equipment	(63,596)	(52,180)
Cash paid for linefill in assets owned	(10,242)	(40,449)
Proceeds from sales of assets	2,234	7,076
Other investing activities		232
Net cash used in investing activities	(567,319)	(185,218)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net repayments on long-term revolving credit facility	(29,977)	(13,122)
Net borrowings on working capital revolving credit facility	34,700	
Net repayments on short-term letter of credit and hedged inventory facility	(42,234)	(67,315)
Principal payments on senior secured term loan		(43,000)
Cash paid in connection with financing arrangements	(3,172)	(87)
Proceeds from the issuance of senior notes	346,427	
Net proceeds from the issuance of common units	262,132	161,905
Distributions paid to unitholders and general partner	(114,468)	(89,346)
Net cash provided by (used in) financing activities	453,408	(50,965)
Effect of translation adjustment on cash	1,270	

	Nine Months Ended September 30,	
Net increase (decrease) in cash and cash equivalents	410	(83)
Cash and cash equivalents, beginning of period	4,137	3,501
Cash and cash equivalents, end of period	$ 4,547	$ 3,418
Cash paid for interest, net of amounts capitalized	$ 23,366	$ 24,286

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL

(in thousands)

	Common Units		Class B Common Units		Class C Common Units		Subordinated Units		General Partners'	Total	Total Partners' Capital
	Units	Amount	Units	Amount	Units	Amount	Units	Amount	Amount	Units	Amount
					(unaudited)						
Balance at December 31, 2003	49,502	$ 744,073	1,307	$ 18,046		$	7,523	$ (39,913)	$ 24,521	58,332	$ 746,727
Issuance of common units	4,968	157,568							3,371	4,968	160,939
Issuance of common units under LTIP	362	11,772							238	362	12,010
Private placement of Class C common units					3,246	98,782			2,041	3,246	100,823
Issuance of units for acquisition contingent consideration	385	13,082							267	385	13,349
Distributions		(96,531)		(2,225)		(3,700)		(4,231)	(7,781)		(114,468)
Other comprehensive income		18,029		410		624		(841)	1,529		19,751
Net income		91,027		2,071		3,150		1,444	7,595		105,287
Conversion of subordinated units	7,523	(43,541)					(7,523)	43,541			
Balance at September 30, 2004	62,740	$ 895,479	1,307	$ 18,302	3,246	$ 98,856		$	$ 31,781	67,293	$ 1,044,418

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME AND CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

(in thousands)

Statements of Comprehensive Income

	Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2003
	(unaudited)	
Net income	$ 105,287	$ 59,620
Other comprehensive income	19,751	61,599
Comprehensive income	$ 125,038	$ 121,219

Statement of Changes in Accumulated Other Comprehensive Income

	Net Deferred Gain (Loss) on Derivative Instruments	Currency Translation Adjustments	Total
		(unaudited)	
Balance at December 31, 2003	$ (7,692)	$ 39,861	$ 32,169
Current period activity:			
Reclassification adjustments for settled contracts	20,265		20,265
Changes in fair value of outstanding hedge positions	(12,160)		(12,160)
Currency translation adjustment		11,646	11,646
Total period activity	8,105	11,646	19,751
Balance at September 30, 2004	$ 413	$ 51,507	$ 51,920

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

Note 1 Organization and Accounting Policies

Plains All American Pipeline, L.P. is a publicly traded Delaware limited partnership (the "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." Our operations are conducted in the United States and Canada, directly and indirectly through our operating subsidiaries, Plains Marketing, L.P., Plains Pipeline, L.P. (formerly known as All American Pipeline, L.P.) and Plains Marketing Canada, L.P.

The accompanying consolidated financial statements and related notes present (i) our consolidated financial position as of September 30, 2004, and December 31, 2003, (ii) the results of our consolidated operations for the nine months ended September 30, 2004 and 2003, (iii) our consolidated cash flows for the nine months ended September 30, 2004 and 2003, (iv) our consolidated changes in partners' capital for the nine months ended September 30, 2004, (v) our consolidated comprehensive income for the nine months ended September 30, 2004 and 2003, and (vi) our changes in consolidated accumulated other comprehensive income for the nine months ended September 30, 2004. The financial statements have been prepared in accordance with the instructions for interim reporting as prescribed by the Securities and Exchange Commission. All adjustments (consisting only of normal recurring adjustments) that in the opinion of management were necessary for a fair statement of the results for the interim periods have been reflected. All significant intercompany transactions have been eliminated. Certain reclassifications are made to prior period amounts to conform to current period presentation. The results of operations for the nine months ended September 30, 2004 should not be taken as indicative of the results to be expected for the full year. The consolidated interim financial statements should be read in conjunction with our consolidated financial statements and notes thereto presented in our 2003 Annual Report on Form 10-K/A Amendment No. 1.

Foreign Currency Transactions

For subsidiaries whose functional currency is not the U.S. Dollar, assets and liabilities are translated at period end rates of exchange and revenues and expenses are translated at average exchange rates prevailing for each month. Translation adjustments for the asset and liability accounts are included as a separate component of other comprehensive income in partners' capital. Currency transaction gains and losses are recorded in income.

Change in Accounting Principle

During the second quarter of 2004, we changed our method of accounting for pipeline linefill in third party assets. Historically, we have viewed pipeline linefill, whether in our assets or third party assets, as having long-term characteristics rather than characteristics typically associated with the short-term classification of operating inventory. Therefore, previously we have not included linefill barrels in the same average costing calculation as our operating inventory, but instead have carried linefill at historical cost. Following this change in accounting principle, the linefill in third party assets that we have historically classified as a portion of "Pipeline Linefill" on the face of the balance sheet (a long-term asset) and carried at historical cost, is included in "Inventory" (a current asset) in determining the average cost of operating inventory and applying the lower of cost or market analysis. At the end of each period, we 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 nine months ended September 30, 2004 and the consolidated balance sheet as of September 30, 2004, included herein. The cumulative effect of this change in accounting principle as of January 1, 2004, is a charge of approximately $3.1 million, representing a reduction in Inventory of approximately $1.7 million, a reduction in Pipeline Linefill of approximately $30.3 million and an increase in Inventory in Third Party Assets of $28.9 million. The pro forma impact for the first nine months of 2003 would have been an increase to net income of approximately $2.2 million ($0.04 per basic and diluted limited partner unit) resulting in pro forma net income of $61.8 million and pro forma basic net income per limited partner unit of $1.10 and pro forma diluted net income per limited partner unit of $1.09.

In conjunction with this change in accounting principle, we have classified cash flows associated with purchases and sales of linefill on assets that we own as cash flows from investing activities instead of the historical classification of cash flows from operating activities. Accordingly, the accompanying statement of cash flows for the nine months ended September 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 $40.4 million for the nine months ended September 30, 2003.

Note 2 Acquisitions and Dispositions

The following acquisitions were made in 2004 and were accounted for under Statement of Financial Accounting Standards ("SFAS") No. 141 "Business Combinations."

Link Energy LLC

On April 1, 2004, we completed the acquisition of all of the North American crude oil and pipeline operations of Link Energy LLC ("Link") for approximately $332 million, including $268 million of cash (net of approximately $5.5 million subsequently returned to us from an indemnity escrow account) and approximately $64 million of net liabilities assumed and acquisition-related costs. The Link crude oil business consists of approximately 7,000 miles of active crude oil pipeline and gathering systems, over 10 million barrels of 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.

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	$ 262.3
Inventory	1.1
Linefill	48.4
Inventory in third party assets	15.1
Goodwill	5.0
Other long term assets	0.2
Subtotal	332.1
Accounts receivable[1]	405.4
Other current assets	1.8
Subtotal	407.2
Total assets acquired	739.3
Fair value of liabilities assumed:	
Accounts payable and accrued liabilities[1]	(455.4)
Other current liabilities	(8.5)
Other long-term liabilities	(7.4)
Total liabilities assumed	(471.3)
Cash paid for acquisition[2]	$ 268.0

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

(2) 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 and related allocation; thus, the purchase price and allocation are both subject to refinement. In addition, we anticipate making capital expenditures of approximately $20.0 million ($9.0 million in 2004) to upgrade certain of the assets and comply with certain regulatory requirements.

The acquisition was initially funded with cash on hand, borrowings under our revolving credit facilities and under a new $200 million, 364-day credit facility and borrowings under our existing revolving credit facilities (see Note 5). In connection with the acquisition, on April 15, 2004, we completed the private placement of 3,245,700 Class C common units to a group of institutional investors. During the third quarter of 2004, we completed a public offering of common units and the sale of an aggregate of $350 million of senior notes. A portion of the proceeds from these transactions was used to retire the $200 million, 364-day credit facility (see Note 7).

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 Attorney General of Texas (the "Texas AG Antitrust Division") 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 (the "FTC"), and that, consistent with federal-state protocols for conducting joint merger investigations, appropriate federal and state antitrust authorities are coordinating their activities. We have cooperated fully with the antitrust enforcement authorities, including the provision of information at the request of the Texas AG Antitrust Division. We have been informed by the Texas AG Antitrust Division that it is closing its investigation and does not intend to pursue any additional course of action with respect to these assets at this time. We have not yet received an indication from the FTC as to whether it intends to close its investigation.

Capline and Capwood Pipeline Systems

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

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

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

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

Pro Forma Data

The following unaudited pro forma data is presented to show pro forma revenues, income before cumulative effect of change in accounting principle, net income, basic and diluted income before cumulative effect of accounting change per limited partner unit and basic and diluted net income per limited partner unit for the Partnership as if the Capline and Link acquisitions had occurred as of the beginning of the periods reported:

	Nine Months Ended September 30,	
	2004	**2003**
	(in millions, except per unit amounts)	
Revenues	$ 14,851.3	$ 9,211.7
Income before cumulative effect of change in accounting principle[1]	$ 91.2	$ 105.3
Net income[2]	$ 88.1	$ 101.3
Basic income before cumulative effect of change in accounting principle per limited partner unit[1]	$ 1.35	$ 1.95
Diluted income before cumulative effect of change in accounting principle per limited partner unit[1]	$ 1.35	$ 1.93
Basic net income per limited partner unit[2]	$ 1.30	$ 1.87
Diluted net income per limited partner unit[2]	$ 1.30	$ 1.86

(1) Includes a net gain in the 2003 period of approximately $67.5 million related to Link's predecessor company's reorganization, discharge of debt and fresh start adjustments.

(2) The 2003 period includes the amounts described in note (1) above as well as a loss of approximately $4.0 million related to Link's predecessor company's cumulative effect of change in accounting principle.

Other Acquisitions

The following acquisitions, both individually and in the aggregate, are not material, and thus, no supplemental pro forma information is included herein.

In August 2004, we completed the acquisition of the Schaefferstown Propane Storage Facility from Koch Hydrocarbon, L.P. The total purchase price was approximately $32 million, including transaction costs. In connection with the transaction, the Partnership also acquired an additional $14.2 million of inventory. The transaction was funded through a combination of cash on hand and borrowings under the Partnership's revolving credit facilities. The 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 19 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. In addition, the transaction also included approximately 61 acres of land and a truck rack. The results of operations and assets from this acquisition have been included in our consolidated financial statements and our gathering, marketing, terminalling and storage operations segment since August 25, 2004. The preliminary purchase price was primarily allocated to property and equipment.

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.

Shutdown and Sale of Rancho Pipeline System

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

Note 3 Trade Accounts Receivable

The majority of our trade accounts receivable relate to our gathering and marketing activities and can generally be described as high volume and low margin activities. As is customary in the industry, a portion of these receivables is reflected net of payables to the same counterparty based on contractual agreements. We routinely review our trade accounts receivable balances to identify past due amounts and analyze the reasons such amounts have not been collected. In many instances, such uncollected amounts involve billing delays and discrepancies or disputes as to the appropriate price, volume or quality of crude oil delivered, received or exchanged. We also attempt to monitor changes in the creditworthiness of our customers as a result of developments related to each customer, the industry as a whole and the general economy. Based on these analyses, as well as our historical experience and the facts and circumstances surrounding certain aged balances, we have established an allowance for doubtful trade accounts receivable. At September 30, 2004, approximately 99% of our net trade accounts receivable were less than 60 days past the scheduled invoice date. Our allowance for doubtful trade accounts receivable totaled $0.5 million. We consider this reserve adequate; however, there is no assurance that actual amounts will not vary significantly from estimated amounts. The discovery of previously unknown facts or adverse developments affecting one of our counterparties or the industry as a whole could adversely impact our results of operations.

Note 4 Inventory and Linefill

Inventory primarily consists of crude oil and LPG in pipelines, storage tanks and rail cars that is valued at the lower of cost or market, with cost determined using an average cost method. Linefill and minimum working inventory requirements are recorded at historical cost and consist of crude oil and LPG used to pack a pipeline such that when an incremental barrel enters a pipeline it forces a barrel out at another location, as well as the minimum amount of crude oil necessary to operate our storage and terminalling facilities.

Linefill in third party assets is included in "Inventory" (a current asset) in determining the average cost of operating inventory and applying the lower of cost or market analysis. At the end of each period, we reclassify the linefill in third party assets not expected to be liquidated within the succeeding twelve months out of "Inventory," at average cost, and into "Inventory in Third Party Assets" (a long-term asset), which is reflected as a separate line item within other assets on the consolidated balance sheet.

At September 30, 2004 and December 31, 2003, inventory and linefill consisted of:

	September 30, 2004			December 31, 2003		
	Barrels	Dollars	$/ barrel	Barrels	Dollars	$/ barrel
	(Barrels in thousands and dollars in millions)					
Inventory[1]						
Crude oil	2,802	$ 110.1	$ 39.29	1,676	$ 50.6	$ 30.19
LPG	3,874	130.3	33.63	2,243	53.8	23.99
Other		1.9	N/A		1.6	N/A
Inventory subtotal	6,676	242.3		3,919	106.0	
Inventory in third-party assets						
Crude oil	1,137	40.6	35.71	853	22.6	26.49
LPG	183	5.7	31.15	183	4.1	22.40
Inventory in third-party assets subtotal	1,320	46.3		1,036	26.7	
Linefill						
Crude oil linefill	5,804	160.0	27.57	3,767	95.9	25.46
Total	13,800	$ 448.6		8,722	$ 228.6	

(1) Value per barrel reflects the impact of inventory hedges on a portion of our volumes.

Note 5 Debt

Debt consists of the following:

	September 30, 2004	December 31, 2003
	(in millions)	
Short-term debt:		
Senior secured hedged inventory borrowing facility bearing interest at a rate of 2.6% and 1.9% at September 30, 2004 and December 31, 2003, respectively	$ 59.5	$ 100.5
Working capital borrowings, bearing interest at a rate of 2.8% and 4.0% at September 30, 2004 and December 31, 2003, respectively[(1)]	60.0	25.3
Other	3.4	1.5
Total short-term debt	122.9	127.3
Long-term debt:		
Senior unsecured $425 million domestic revolving credit facility, bearing interest at 4.8% at September 30, 2004[(1)]	$ 18.6	$
Senior unsecured $30 million Canadian working capital revolving credit facility, bearing interest at a rate of 4.6% at September 30, 2004	11.4	
Senior unsecured $170 million Canadian revolving credit facility, bearing interest at a rate of 2.8% and 2.2% at September 30, 2004 and December 31, 2003, respectively	10.0	70.0
4.75% senior notes due August 2009, net of unamortized discount of $0.8 million at September 30, 2004	174.2	
7.75% senior notes due October 2012, net of unamortized discount of $0.3 million and $0.3 million at September 30, 2004 and December 31, 2003, respectively	199.7	199.7
5.63% senior notes due December 2013, net of unamortized discount of $0.6 million and $0.7 million at September 30, 2004 and December 31, 2003, respectively	249.4	249.3
5.88% senior notes due August 2016, net of unamortized discount of $1.1 million at September 30, 2004	173.9	
Other	0.4	
Total long-term debt[(1)(2)]	837.6	519.0
Total debt	$ 960.5	$ 646.3

(1) At September 30, 2004 and December 31, 2003, we have classified $60.0 million and $25.3 million, respectively, of borrowings under our senior unsecured $425 million domestic revolving credit facility as short-term. These borrowings are designated as working capital borrowings and primarily are for hedged LPG inventory and New York Mercantile Exchange margin deposits and must be repaid within one year.

(2) At September 30, 2004, the aggregate fair value of our fixed rate senior notes was approximately $854.8 million.

During August 2004, we completed the sale of $175 million of 4.75% Senior Notes due 2009 and $175 million of 5.88% Senior Notes due 2016. The 4.75% notes were sold at 99.551% of face value and the 5.88% notes were sold at 99.345% of face value. The notes were co-issued by Plains All American

Pipeline, L.P. and a 100% owned consolidated finance subsidiary (neither of which have independent assets or operations). Interest payments are due on 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 which are minor. We used the proceeds to repay amounts outstanding under our credit facilities, including the remaining balance under the $200 million, 364-day facility described above, and for general partnership purposes. In connection with this repayment, we terminated the facility. The repayment and termination of this facility resulted in a non-cash charge of approximately $0.7 million associated with the write-off of unamortized debt issue costs. Subsequent to the notes offering, we also terminated our $125 million, 364-day facility which was scheduled to expire in November 2004.

In the third quarter of 2004, we increased our secured hedged inventory facility from $200 million to $300 million, with the ability to further increase the facility in the future by an incremental $200 million. This facility is an uncommitted working capital facility, which is used to finance the purchase of hedged crude oil inventory for storage when market conditions warrant. Borrowings under the hedged inventory facility are secured by the inventory purchased under the facility and the associated accounts receivable, and are repaid with the proceeds from the sale of such inventory. This facility expires in November 2004, and we expect to extend the maturity to November 2005 before expiration.

In November 2004, we entered into a new $750 million, five-year senior credit facility, which contains a sub-facility for Canadian borrowings up to $300 million. The new facility extends our maturities, lowers our cost of credit and provides an additional $125 million of liquidity over our previous facility. The facility can be expanded to $1 billion.

Note 6 Earnings Per Common Unit

The following sets forth the computation of basic and diluted earnings per common unit:

	Nine months ended September 30, 2004	Nine months ended September 30, 2003
	(in thousands, except per unit data)	
Net income	$ 105,287	$ 59,620
Less:		
Incentive distribution right	(5,601)	(3,540)
Subtotal	99,686	56,080
General partner 2% ownership	(1,994)	(1,122)
Numerator:		
Numerator for basic earnings per limited partner unit		
Net income available for limited partners	97,692	54,958
Effect of dilutive securities:		
Increase in incentive distribution right-contingent equity issuance		(46)
Numerator for diluted earnings per limited partner unit	$ 97,692	$ 54,912
Denominator:		
Denominator for basic earnings per limited partner unit weighted average number of limited partner units	61,929	51,735
Effect of dilutive securities:		
Contingent equity issuance		672
Denominator for diluted earnings per limited partner unit	61,929	52,407
Basic net income per limited partner unit	$ 1.58	$ 1.06
Diluted net income per limited partner unit	$ 1.58	$ 1.05

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 did not result in a change in the Partnership's earnings per limited partner unit for any of the periods presented.

Note 7 Partners' Capital and Distributions

Subordinated Unit Conversion

In November 2003, pursuant to the terms of our Partnership Agreement, 25% of our subordinated units converted to common units on a one-for-one basis. In February 2004, all of the remaining subordinated units converted to common units on a one-for-one basis.

Issuance of Common Units

Long-Term Incentive Plan. We issued approximately 315,500 common units during the first half of 2004 and approximately 47,500 common units during the third quarter of 2004 in conjunction with the vesting of awards under our Long-Term Incentive Plan ("LTIP"). In connection with such issuances, the General Partner made a proportionate two percent contribution. See Note 8 for additional discussion.

Payment of Deferred Acquisition Price. On April 30, 2004, we issued approximately 385,000 common units and paid approximately $6.5 million in cash to satisfy the contingent consideration related to the July 2001 CANPET acquisition. In accordance with the provisions of the purchase and sale agreement, the number of common units issued in satisfaction of the deferred payment was based upon $34.02 per share, the average trading price of our common units for the ten-day trading period prior to the payment date, and a Canadian dollar to U.S. dollar exchange rate of 1.35 to 1, the average noon-day exchange rate for the ten-day trading period prior to the payment date. In addition, an incremental $3.7 million in cash was paid for the distributions that would have been paid on the common units had they been outstanding since the effective date of the acquisition.

Private Placement of Class C Common Units. In connection with the Link acquisition, on April 15, 2004 we issued 3,245,700 Class C common units for $30.81 per unit in a private placement to a group of institutional investors consisting of affiliates of Kayne Anderson Capital Advisors, Vulcan Capital and Tortoise Capital Advisors. Affiliates of both Kayne Anderson Capital Advisors and Vulcan Capital own interests in our general partner. Total proceeds from the transaction, after deducting transaction costs and including the general partner's proportionate contribution, were approximately $101 million, and were used to reduce the balance outstanding under our revolving credit facilities. The Class C common units are unlisted securities that are *pari passu* in voting and distribution rights with the Partnership's publicly traded common units. The Class C common units are similar in most respects to the Partnership's Class B common units. Both classes become convertible into common units upon approval by the holders of a majority of the common units. See "Class B and Class C Common; Unitholder Meeting."

Class B and Class C Common; Unitholder Meeting. Each of the Class B common unitholders and Class C common unitholders may request that the Partnership call a meeting of its common unitholders to consider approval of a change in the terms of the Class B units or Class C units, as applicable, to provide that those units may be converted at the option of the holder into common units. The holders of both the Class B common units and the Class C common units made such a request on October 18, 2004. If the approval of the common unitholders is not obtained within 120 days of the request, the holders of the Class B and Class C units (unless and until converted into common units) will be entitled to receive distributions, on a per unit basis, equal to 110% of the amount of distributions paid on a common unit. If the approval of the common unitholders is not secured within 90 days after the end of the 120-day period, the distribution right increases to 115%. The Partnership is in the process of preparing for a meeting of unitholders.

Equity Offering. In the third quarter of 2004, we completed a public offering of 4,968,000 common units for $33.25 per unit. The offering resulted in gross proceeds of approximately $165.2 million from the sale of units and approximately $3.4 million from our general partner's proportionate capital contribution. Total costs associated with the offering, including underwriter fees and other expenses, were approximately $7.7 million. Net proceeds of $160.9 million were used to permanently reduce outstanding borrowings under the $200 million, 364-day credit facility (see Note 5).

Distributions

On October 22, 2004, we declared a cash distribution of $0.60 per unit on our outstanding common units, Class B common units and Class C common units. The distribution is payable on November 12, 2004, to unitholders of record on November 2, 2004, for the period July 1, 2004, through September 30, 2004. The total distribution to be paid is approximately $43.9 million, with approximately $40.4 million to be paid to our common unitholders and $0.8 million and $2.7 million to be paid to our general partner for its general partner and incentive distribution interests, respectively.

On August 13, 2004, we paid a cash distribution of $0.5775 per unit on our outstanding common units, Class B common units and Class C common units, for the period April 1, 2004, through June 30, 2004. The total distribution paid was approximately $41.8 million, with approximately $38.8 million paid to our common unitholders and $0.8 million and $2.2 million paid to our general partner for its general partner and incentive distribution interests, respectively.

On May 14, 2004, we paid a cash distribution of $0.5625 per unit on our outstanding common units, Class B common units and Class C common units, for the period January 1, 2004, through March 31, 2004. The total distribution paid was approximately $37.5 million, with approximately $35.0 million paid to our common unitholders and $0.7 million and $1.8 million paid to our general partner for its general partner and incentive distribution interests, respectively.

On February 13, 2004, we paid a cash distribution of $0.5625 per unit on our outstanding common units, Class B common units and subordinated units, for the period October 1, 2003, through December 31, 2003. The total distribution paid was approximately $35.2 million, with approximately $28.7 million paid to our common unitholders, $4.2 million paid to our subordinated unitholders and $0.7 million and $1.6 million paid to our general partner for its general partner and incentive distribution interests, respectively.

Note 8 Vesting of Unit Grants Under Long-Term Incentive Plan

During the first nine months of 2004, approximately 895,000 phantom units vested. We paid cash in lieu of delivery of common units for approximately 328,000 of the phantom units and issued approximately 362,000 new common units (after netting for taxes) in connection with the remainder of the vesting.

Under generally accepted accounting principles, we are required to recognize an expense when it is considered probable that phantom unit grants under our LTIP will vest. During the first nine months of

2004, we recognized $4.2 million of compensation expense related to the vesting of phantom units under the LTIP. We will recognize additional expense when it is considered probable that additional vestings will occur. Generally, future vestings will occur when the annualized distribution rate reaches $2.50 and again at $2.70. After giving effect to the third quarter 2004 vesting and related tax withholding and cash settlement, approximately 874,000 phantom units are available under the plan for future grant and approximately 134,000 phantom units remain outstanding. In accordance with the provisions of the LTIP and applicable NYSE standards, no more than approximately 460,000 of such phantom unit grants (outstanding or future) could be satisfied by delivery of common units.

Note 9 Derivative Instruments and Hedging Activities

We utilize various derivative instruments to (i) manage our exposure to commodity price risk, (ii) engage in a controlled trading program, (iii) manage our exposure to interest rate risk and (iv) manage our exposure to currency exchange rate risk. Our risk management policies and procedures are designed to monitor interest rates, currency exchange rates, NYMEX and over-the-counter positions, and physical volumes, grades, locations and delivery schedules to ensure that our hedging activities address our market risks. We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategy for undertaking the hedge. We calculate hedge effectiveness on a quarterly basis. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument's effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items.

Summary of Financial Impact

The following is a summary of the financial impact of the derivative instruments and hedging activities discussed below. The September 30, 2004, balance sheet includes assets of $53.6 million ($39.5 million current), liabilities of $43.9 million ($32.8 million current) and unrealized net gains deferred to Other Comprehensive Income ("OCI") of $0.4 million. Total derivative activities for the nine months ended September 30, 2004, generated a gain of $66.3 million. Total derivative activities include the mark-to-market of open positions that do not meet hedge accounting requirements and gains and losses recognized in earnings for all hedges settled during the period. The majority of these gains are related to our commodity price risk hedges that are offset by physical transactions, as discussed below.

As of September 30, 2004, the total amount of deferred net gains recorded in OCI are expected to be reclassified to future earnings, contemporaneously with the related physical purchase or delivery of the underlying commodity or payments of interest. During the nine months ended September 30, 2004, no amounts were reclassified to earnings from OCI in connection with forecasted transactions that were no longer considered probable of occurring. Of the $0.4 million net gain deferred in OCI at September 30, 2004, a net gain of $7.3 million will be reclassified into earnings in the next twelve months and the remaining net loss at various intervals ending in 2016. Since a portion of these amounts is based on market prices at the current period end, actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

The following sections discuss our risk management activities in the indicated categories.

Commodity Price Risk Hedging

We hedge our exposure to price fluctuations with respect to crude oil and LPG in storage, and expected purchases, sales and transportation of these commodities. The derivative instruments we use consist primarily of futures and option contracts traded on the NYMEX and over-the-counter transactions, including crude oil swap and option contracts entered into with financial institutions and other energy companies. In accordance with SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities," these derivative instruments are recognized in the balance sheet or earnings at their fair values. The majority of the instruments that qualify for hedge accounting are cash flow hedges. Therefore, the corresponding changes in fair value for the effective portion of the hedges are deferred into OCI and recognized in revenues or crude oil and LPG purchases and related costs in the periods during which the underlying physical transactions occur. We have determined that substantially all of our physical purchase and sale agreements qualify for the normal purchase and sale exclusion and thus are not subject to SFAS 133. Physical transactions that are derivatives and are ineligible, or become ineligible, for the normal purchase and sale treatment (e.g. due to changes in settlement provisions) are recorded in the balance sheet as assets or liabilities at their fair value, with the changes in fair value recorded net in revenues.

Controlled Trading Program

Although we seek to maintain a position that is substantially balanced within our crude oil lease purchase activities, we may experience net unbalanced positions for short periods of time as a result of production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions. In connection with managing these positions and maintaining a constant presence in the marketplace, both necessary for our core business, we engage in a controlled trading program for up to an aggregate of 500,000 barrels of crude oil. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. In accordance with SFAS 133, these derivative instruments are recorded in the balance sheet as assets or liabilities at their fair value, with the changes in fair value recorded net in revenues.

Interest Rate Risk Hedging

At September 30, 2004, we have no open interest rate hedging instruments. However, there are approximately $6.5 million deferred in OCI that relates to instruments that were terminated and cash settled ($1.4 million related to an instrument settled in 2004 and $5.1 million related to instruments settled in 2003). The net deferred loss related to these instruments is being amortized into interest expense over the original terms of the terminated instruments (approximately forty percent over the next two years and the remaining sixty percent over approximately ten years). Approximately $1.1 million related to the terminated instruments has been reclassified into interest expense during the first nine months of 2004, and approximately $1.5 million will be reclassified for the entire year of 2004. In addition, earnings for the first nine months of 2004 include a loss of approximately $0.7 million that was reclassified out of OCI related to an instrument that matured in March 2004.

Currency Exchange Rate Risk Hedging

Because a significant portion of our Canadian business is conducted in Canadian dollars and, at times, a portion of our debt is denominated in Canadian dollars, we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments include forward exchange contracts and cross currency swaps. The forward exchange contracts qualify for hedge accounting as cash flow hedges and the cross currency swaps qualify for hedge accounting as fair value hedges, both in accordance with SFAS 133.

At September 30, 2004, we had forward exchange contracts that allow us to exchange Canadian dollars for U.S. dollars, quarterly, at set exchange rates as detailed below:

	Canadian Dollars	US Dollars	Rate
	($ in millions)		
2004	$ 5.0	$ 3.8	1.32 to 1
2005	$ 3.0	$ 2.3	1.33 to 1
2006	$ 2.0	$ 1.5	1.32 to 1

In addition, at September 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 will reduce by $2.0 million U.S. in May 2005 and has a final maturity in May 2006 of $19.0 million U.S. At September 30, 2004, $6.2 million of our long-term debt was denominated in Canadian dollars ($7.8 million Canadian based on a Canadian dollar to U.S. dollar exchange rate of 1.26 to 1). All of these financial instruments are placed with what we believe to be large, creditworthy financial institutions.

Note 10 Commitments and Contingencies

Litigation

Export License Matter. In our gathering and marketing activities, we import and export crude oil from and to Canada. Exports of crude oil are subject to the short supply controls of the Export Administration Regulations ("EAR") and must be licensed by the Bureau of Industry and Security (the "BIS") of the U.S. 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 have 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. We have received a request from the BIS for additional information, which we are in the process of providing. 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.

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

Environmental

We may experience future releases of crude oil into the environment from our pipeline and storage operations, or discover past releases that were previously unidentified. Although we maintain an inspection program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to any such environmental releases from our assets may substantially affect our business. At September 30, 2004, our reserve for environmental liabilities totaled approximately $21.4 million. Approximately $13.8 million of the reserve is related to liabilities assumed as part of the Link acquisition. Although we believe our reserve is adequate, no assurance can be given that any costs incurred in excess of this reserve would not have a material adverse effect on our financial condition, results of operations or cash flows.

Other

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

Note 11 Operating Segments

Our operations consist of two operating segments: (1) Pipeline Operations, which engage in interstate and intrastate crude oil pipeline transportation and certain related margin activities; and (2) Gathering, Marketing, Terminalling and Storage Operations, which 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 believe that the combination of our terminalling and storage activities and gathering and marketing activities provides a counter-cyclical balance that has a stabilizing effect on our results of operations and cash flow. In a contango market (oil prices for future deliveries are higher than for current deliveries), we use our tankage to improve our gathering margins by storing crude oil we have purchased at lower prices in the current month for delivery at higher prices in future months. In a backwardated market (oil prices for future deliveries are lower than for current deliveries), we use and lease less storage capacity, but increased marketing margins (premiums for prompt delivery) provide an offset to this reduced cash flow.

We evaluate segment performance based on segment profit and maintenance capital. We define segment profit as revenues less (i) purchases, (ii) field operating costs, and (iii) segment general and administrative expenses. Maintenance capital consists of capital expenditures required either to maintain the existing operating capacity of partially or fully depreciated assets or to extend their useful lives. Capital expenditures made to expand our existing capacity, whether through construction or acquisition, are not considered maintenance capital expenditures. Repair and maintenance expenditures associated with existing assets that do not extend the useful life or expand the operating capacity are charged to expense as incurred. The following table reflects our results of operations for each segment for the periods indicated (note that each of the items in the following table excludes depreciation and amortization):

	Pipeline	GMT&S	Total
		(in millions)	
Nine Months Ended September 30, 2004			
Revenues:			
External Customers	$ 556.5	$ 14,246.9	$ 14,803.4
Intersegment[1]	83.0	0.7	83.7
Total revenues of reportable segments	$ 639.5	$ 14,247.6	$ 14,887.1
Segment profit	$ 117.2	$ 68.9	$ 186.1
Total assets	$ 1,100.5	$ 2,005.5	$ 3,106.0
Non-cash SFAS 133 impact[2]	$	$ 1.4	$ 1.4
Maintenance capital	$ 4.1	$ 2.0	$ 6.1
Nine Months Ended September 30, 2003			
Revenues:			
External Customers	$ 450.6	$ 8,594.1	$ 9,044.7
Intersegment[1]	38.5	0.7	39.2
Total revenues of reportable segments	$ 489.1	$ 8,594.8	$ 9,083.9
Segment profit	$ 67.2	$ 52.9	$ 120.1
Non-cash SFAS 133 impact[2]	$	$ (1.7)	$ (1.7)
Maintenance capital	$ 4.8	$ 0.7	$ 5.5

(1) Intersegment sales are conducted at arms length.

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

The following table reconciles segment profit to consolidated income before cumulative effect of change in accounting principle:

	For the nine months ended September 30, 2004	For the nine months ended September 30, 2003
	(in millions)	
Segment profit	$ 186.1	$ 120.1
Depreciation and amortization	(45.9)	(34.2)
Interest expense	(32.2)	(26.5)
Interest income and other, net	0.4	0.2
Income before cumulative effect of change in accounting principle	$ 108.4	$ 59.6

Report of Independent Registered Public Accounting Firm

To the Board of Directors of the General Partner and Unitholders of
Plains All American Pipeline, L.P.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of cash flows, of changes in partners' capital, of comprehensive income and of changes in accumulated other comprehensive income (loss) present fairly, in all material respects, the financial position of Plains All American Pipeline, L.P. and its subsidiaries (the "Partnership") at December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the consolidated financial statements, the Partnership changed its method of accounting for derivative instruments and hedging activities effective January 1, 2001.

PricewaterhouseCoopers LLP

Houston, Texas
February 26, 2004, except as to Note 1
which is as of July 21, 2004

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands, except unit data)

	December 31, 2003	December 31, 2002
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 4,137	$ 3,501
Accounts receivable, net	590,645	499,909
Inventory	105,967	81,849
Other current assets	32,225	17,676
Total current assets	732,974	602,935
PROPERTY AND EQUIPMENT	1,272,634	1,030,303
Accumulated depreciation	(121,595)	(77,550)
	1,151,039	952,753
OTHER ASSETS		
Pipeline linefill	122,653	62,558
Other, net	88,965	48,329
Total assets	$ 2,095,631	$ 1,666,575
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable	$ 603,460	$ 488,922
Due to related parties	26,981	23,301
Short-term debt (see Note 6)	127,259	99,249
Other current liabilities	44,219	25,777
Total current liabilities	801,919	637,249
LONG-TERM LIABILITIES		
Long-term debt under credit facilities, including current maturities of $9,000 for the 2002 period	70,000	310,126
Senior notes, net of unamortized discount of $1,009 and $390, respectively	448,991	199,610
Other long-term liabilities and deferred credits	27,994	7,980
Total liabilities	1,348,904	1,154,965
COMMITMENTS AND CONTINGENCIES (NOTE 12)		
PARTNERS' CAPITAL		
Common unitholders (49,502,556 and 38,240,939 units outstanding at December 31, 2003, and December 31, 2002, respectively)	744,073	524,428
Class B common unitholder (1,307,190 units outstanding at each date)	18,046	18,463
Subordinated unitholders (7,522,214 and 10,029,619 units outstanding at December 31, 2003, and December 31, 2002, respectively)	(39,913)	(47,103)

	December 31, 2003	December 31, 2002
General partner	24,521	15,822
Total partners' capital	746,727	511,610
	$ 2,095,631	$ 1,666,575

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

	Year Ended December 31,		
	2003	**2002**	**2001**
REVENUES			
Crude oil and LPG sales	$ 11,952,623	$ 7,892,162	$ 6,481,305
Pipeline margin activities	505,287	382,513	285,618
Pipeline tariffs and fees	99,887	79,939	54,234
Other	32,052	29,609	47,058
Total revenues	12,589,849	8,384,223	6,868,215
COSTS AND EXPENSES			
Crude oil and LPG purchases and related costs	11,727,355	7,726,323	6,338,365
Pipeline margin activities purchases	486,154	362,311	270,786
Other purchases	19,027	14,862	4,965
Field operating costs (excluding LTIP charge)	134,177	106,436	106,854
LTIP charge operations	5,727		
Inventory valuation adjustment			4,984
General and administrative (excluding LTIP charge)	49,969	45,663	46,586
LTIP charge general and administrative	23,063		
Depreciation and amortization	46,821	34,068	24,307
Total costs and expenses	12,492,293	8,289,663	6,796,847
Gains on sales of assets	648		984
OPERATING INCOME	98,204	94,560	72,352
OTHER INCOME/(EXPENSE)			
Interest expense (net of capitalized interest of $524, $773 and $153)	(35,226)	(29,057)	(29,082)
Interest income and other, net (Note 2)	(3,530)	(211)	401
Income before cumulative effect of accounting change	59,448	65,292	43,671
Cumulative effect of accounting change			508
NET INCOME	$ 59,448	$ 65,292	$ 44,179
NET INCOME-LIMITED PARTNERS	$ 53,473	$ 60,912	$ 42,239
NET INCOME-GENERAL PARTNER	$ 5,975	$ 4,380	$ 1,940
BASIC NET INCOME PER LIMITED PARTNER UNIT			
Income before cumulative effect of accounting change	$ 1.01	$ 1.34	$ 1.12
Cumulative effect of accounting change			0.01
Net income	$ 1.01	$ 1.34	$ 1.13
DILUTED NET INCOME PER LIMITED PARTNER UNIT			

	Year Ended December 31,		
Income before cumulative effect of accounting change	$ 1.00	$ 1.34	$ 1.12
Cumulative effect of accounting change			0.01
Net Income	$ 1.00	$ 1.34	$ 1.13
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	52,743	45,546	37,528
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	53,400	45,546	37,528

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended December 31,		
	2003	**2002**	**2001**
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 59,448	$ 65,292	$ 44,179
Adjustments to reconcile to cash flows from operating activities:			
Depreciation and amortization	46,821	34,068	24,307
Gains on sales of assets	(648)		(984)
Cumulative effect of accounting change			(508)
Noncash compensation expense			5,741
Allowance for doubtful accounts	360	146	3,000
Inventory valuation adjustment			4,984
Change in derivative fair value	(363)	(243)	(207)
Net cash paid for termination of interest rate hedging instruments	(6,152)		
Write-off of unamortized debt issue costs	3,272		
Noncash portion of LTIP charge (Note 11)	28,052		
Changes in assets and liabilities, net of acquisitions:			
Accounts receivable and other	(102,005)	(136,480)	(18,856)
Inventory	(38,941)	105,944	(117,878)
Accounts payable and other current liabilities	117,412	106,065	46,671
Other long-term liabilities and deferred credits	4,600	1,200	600
Due to related parties	3,452	8,962	(7,266)
Net cash provided by (used in) operating activities	115,308	184,954	(16,217)
CASH FLOWS FROM INVESTING ACTIVITIES			
Cash paid in connection with acquisitions (Note 3)	(168,359)	(324,628)	(229,162)
Additions to property and equipment	(65,416)	(40,590)	(21,069)
Cash paid for linefill on assets owned	(46,790)	(11,060)	(13,736)
Proceeds from sales of assets	8,450	1,437	740
Net cash used in investing activities	(272,115)	(374,841)	(263,227)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net borrowings/(repayments) on short-term letter of credit and hedged inventory facilities	(6,197)	(4,770)	99,583
Net borrowings/(repayments) on long-term revolving credit facilities	87,773	(42,144)	34,677
Principal payments on senior secured term loans (Note 6)	(297,000)	(3,000)	
Cash paid in connection with financing arrangements	(5,191)	(5,435)	(6,351)
Net proceeds from the issuance of common units (Note 7)	250,341	145,046	227,549
Proceeds from the issuance of senior unsecured notes (Note 6)	249,340	199,600	
Distributions paid to unitholders and general partner (Note 7)	(121,822)	(99,841)	(75,929)
Net cash provided by financing activities	157,244	189,456	279,529
Effect of translation adjustment on cash	199	421	

	Year Ended December 31,		
Net increase (decrease) in cash and cash equivalents	636	(10)	85
Cash and cash equivalents, beginning of period	3,501	3,511	3,426
Cash and cash equivalents, end of period	$ 4,137	$ 3,501	$ 3,511
Cash paid for interest, net of amounts capitalized	$ 36,382	$ 28,550	$ 33,341

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CHANGES IN PARTNERS' CAPITAL

(in thousands)

	Common Unitholders		Class B Common Unitholders		Subordinated Unitholders		General Partner	Total Partners' Capital
	Units	Amount	Units	Amount	Units	Amount	Amount	Amount
Balance at December 31, 2000	23,049	$ 217,073	1,307	$ 21,042	10,030	$ (27,316)	$ 3,200	$ 213,999
Issuance of units	8,867	222,032					5,517	227,549
Noncash compensation expense							5,741	5,741
Net income		29,436		1,476		11,327	1,940	44,179
Distributions		(51,271)		(2,549)		(19,558)	(2,551)	(75,929)
Other comprehensive loss		(8,708)		(435)		(3,344)	(255)	(12,742)
Balance at December 31, 2001	31,916	408,562	1,307	19,534	10,030	(38,891)	13,592	402,797
Issuance of units	6,325	142,013					3,033	145,046
Net income		45,857		1,736		13,319	4,380	65,292
Distributions		(70,821)		(2,762)		(21,188)	(5,070)	(99,841)
Other comprehensive loss		(1,183)		(45)		(343)	(113)	(1,684)
Balance at December 31, 2002	38,241	524,428	1,307	18,463	10,030	(47,103)	15,822	511,610
Issuance of units	8,736	245,093					5,237	250,330
Issuance of units under LTIP	18	555					11	566
Net income		41,278		1,370		10,825	5,975	59,448
Conversion of 25% of subordinated units	2,507	(9,823)			(2,507)	9,823		
Distributions		(89,801)		(2,860)		(21,939)	(7,222)	(121,822)
Other comprehensive income		32,343		1,073		8,481	4,698	46,595
Balance at December 31, 2003	49,502	$ 744,073	1,307	$ 18,046	7,523	$ (39,913)	$ 24,521	$ 746,727

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2003	2002	2001
		(in thousands)	
Net income	$ 59,448	$ 65,292	$ 44,179
Other comprehensive income (loss)	46,595	(1,684)	(12,742)
Comprehensive income	$ 106,043	$ 63,608	$ 31,437

CONSOLIDATED STATEMENT OF CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	Net Deferred Loss on Derivative Instruments	Currency Translation Adjustments	Total
		(in thousands)	
Balance at December 31, 2000	$	$	$
Cumulative effect of accounting change	(8,337)		(8,337)
Reclassification adjustments for settled contracts	(2,526)		(2,526)
Changes in fair value of outstanding hedge positions	6,123		6,123
Currency translation adjustment		(8,002)	(8,002)
Balance at December 31, 2001	(4,740)	(8,002)	(12,742)
Reclassification adjustments for settled contracts	797		797
Changes in fair value of outstanding hedge positions	(4,264)		(4,264)
Currency translation adjustment		1,783	1,783
2002 Activity	(3,467)	1,783	(1,684)
Balance at December 31, 2002	(8,207)	(6,219)	(14,426)
Reclassification adjustments for settled contracts	(28,151)		(28,151)
Changes in fair value of outstanding hedge positions	28,666		28,666
Currency translation adjustment		46,080	46,080
2003 Activity	515	46,080	46,595
Balance at December 31, 2003	$ (7,692)	$ 39,861	$ 32,169

The accompanying notes are an integral part of these consolidated financial statements.

Note 1 Organization and Basis of Presentation

Organization

Plains All American Pipeline, L.P. is a publicly traded Delaware limited partnership (the "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 liquified petroleum gas and other petroleum products collectively as "LPG". 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 ("Plains Resources") as a separate, publicly traded master limited partnership. We completed our initial public offering in November 1998. 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 Plains Resources' limited partner units (the "General Partner Transition"), Plains Resources' overall effective ownership in us was reduced to approximately 22%.

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. Plains All American GP LLC manages our operations and activities and employs our officers and personnel, who devote 100% of their efforts to the management of the Partnership. Unless the context otherwise requires, we use the term "general partner" to refer to both Plains AAP, L.P. and Plains All American GP LLC. Plains AAP, L.P. and Plains All American GP LLC are essentially held by 7 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.

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., and are concentrated in Texas, Oklahoma, California, Louisiana and the Canadian provinces of Alberta and Saskatchewan.

Change in Accounting Principle

During the second quarter of 2004, we changed our method of accounting for pipeline linefill in third party assets. Historically, we have viewed pipeline linefill, whether in our assets or third party assets, as having long-term characteristics rather than characteristics typically associated with the short-term classification of operating inventory. Therefore, previously we have not included linefill barrels in the same average costing calculation as our operating inventory, but instead have carried linefill at historical cost. Following this change in accounting principle, the linefill in third party assets that we have historically classified as a portion of "Pipeline Linefill" on the face of the balance sheet (a long-term asset) and carried at historical cost, 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. 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 on net income and net income per limited partner unit (basic and diluted) presented below gives effect to the retroactive application of the change in accounting for pipeline linefill in third party assets had the new method been in effect in the years presented.

	2003	2002	2001
	(in millions, except per unit data)		
Income before cumulative effect of accounting change	$ 59.4	$ 65.3	$ 43.7
Income before cumulative effect of accounting change per limited partner unit:			
Basic	$ 1.01	$ 1.34	$ 1.12
Diluted	$ 1.00	$ 1.34	$ 1.12
Net Income	$ 59.4	$ 65.3	$ 44.2
Net Income per limited partner unit:			
Basic	$ 1.01	$ 1.34	$ 1.13
Diluted	$ 1.00	$ 1.34	$ 1.13
Pro Forma Income before cumulative effect of accounting change	$ 61.4	$ 64.8	$ 38.4
Pro Forma Income before cumulative effect of accounting change per limited partner unit:			
Basic	$ 1.05	$ 1.33	$ 0.97
Diluted	$ 1.04	$ 1.33	$ 0.97
Pro Forma Net Income	$ 61.4	$ 64.8	$ 38.9
Pro Forma Net Income per limited partner unit:			
Basic	$ 1.05	$ 1.33	$ 0.99
Diluted	$ 1.04	$ 1.33	$ 0.99

In conjunction with this change in accounting principle, we have classified the 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 accompanying statement of cash flows for the year ended December 31, 2003, 2002 and 2001 has been revised to reclassify the cash paid for linefill in assets owned from operating activities to investing activities. As a result of this change in classification, net cash provided by operating activities for the years ended December 31, 2003 and 2002 increased to $115.3 million from $68.5 million and to $185.0 million from $173.9 million, respectively. Net cash used in investing activities for the years ended December 31, 2003 and 2002 increased to $272.1 million from $225.3 million and $374.8 million from $363.8 million, respectively. In addition, net cash used in operating activities for the year ended December 31, 2001 decreased from $30 million to $16.2 million and net cash used in investing activities increased to $263.2 million from $249.5 million.

Basis of Consolidation and Presentation

The accompanying financial statements and related notes present our consolidated financial position as of December 31, 2003 and 2002, and the consolidated results of our operations, cash flows, changes in partners' capital and comprehensive income (loss) for the years ended December 31, 2003, 2002 and 2001, and changes in accumulated other comprehensive income for the years ended December 31, 2003 and 2002. All significant intercompany transactions have been eliminated. Certain reclassifications were made to prior periods to conform with the current period presentation.

Note 2 Summary of Significant Accounting Policies

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates we make include: (i) accruals related to purchases and sales, (ii) mark-to-market estimates pursuant to Statement of Financial Accounting Standards ("SFAS") No. 133 "Accounting For Derivative Instruments and Hedging Activities", as amended, (iii) contingent liability accruals, (iv) accruals related to our Long-Term Incentive Plan (the "LTIP") and (v) estimated fair value of assets and liabilities acquired and identification of associated goodwill and intangible assets. Although we believe these estimates are reasonable, actual results could differ from these estimates.

Revenue Recognition

Gathering, Marketing, Terminalling and Storage Segment Revenues. Revenues from crude oil and LPG sales are recognized at the time title to the product sold transfers to the purchaser, which occurs upon receipt of the product by the purchaser. All sales of crude oil and LPG are booked gross except in the case of barrel exchanges that are net settled. Terminalling and storage revenues, which are classified as other revenues on the income statement, consist of (i) storage fees from actual storage used on a month-to-month basis; (ii) storage fees resulting from short-term and long-term contracts for committed space that may or may not be utilized by the customer on a given month; and (iii) terminal throughput charges to pump crude oil to connecting carriers. Revenues on storage are recognized ratably over the term of the contract. Terminal throughput charges are recognized as the crude oil exits the terminal and is delivered to the connecting crude oil carrier. Any throughput volumes in transit at the end of a given month are treated as third party inventory and do not incur storage fees. All terminalling and storage revenues are based on actual volumes and rates.

Pipeline Segment Revenues. Pipeline margin activities primarily consist of the purchase and sale of crude oil shipped on our San Joaquin Valley system from barrel exchanges and buy/sell arrangements. Revenues associated with these activities are recognized at the time title to the product sold transfers to the purchaser, which occurs upon receipt of the product by the purchaser. Revenues for these transactions are recorded gross except in the case of barrel exchanges that are net settled. All of our pipeline margin activities revenues are based on actual volumes and prices. Revenues from pipeline tariffs and fees are associated with the transportation of crude oil at a published tariff as well as fees associated with line leases for committed space on a particular system that may or may not be utilized. Tariff revenues are recognized either at the point of delivery or at the point of receipt pursuant to specifications outlined in the regulated and non-regulated tariffs. Revenues associated with line lease fees are recognized in the month to which the lease applies, whether or not the space is actually utilized. All pipeline tariff and fee revenues are based on actual volumes and rates.

Purchases and Related Costs

Purchases and related costs include: (i) the cost of crude oil and LPG purchased; (ii) third party transportation and storage, whether by pipeline, truck or barge; and (iii) expenses to issue letters of credit to support these purchases. These purchases are accrued at the time title transfers to us which occurs upon receipt of the product.

Operating Expenses and General and Administrative Expenses

Operating expenses consist of various field and pipeline operating expenses including fuel and power costs, telecommunications, labor costs for truck drivers and pipeline field personnel, maintenance costs, regulatory compliance, insurance, vehicle leases, and property taxes. General and administrative expenses consist primarily of payroll and benefit costs, certain information system and legal costs, office rent, contract and consultant costs, and audit and tax fees.

Cash and Cash Equivalents

Cash and cash equivalents consist of all demand deposits and funds invested in highly liquid instruments with original maturities of three months or less and at times may exceed federally insured limits. We periodically assess the financial condition of the institutions where these funds are held and believe that any possible credit risk is minimal.

Accounts Receivable

Our accounts receivable are primarily from purchasers and shippers of crude oil. There were no amounts due from related parties at December 31, 2003 or 2002. The majority of our accounts receivable relate to our gathering and marketing activities that can generally be described as high volume and low margin activities, in many cases involving complex exchanges of crude oil volumes. We make a determination of the amount, if any, of the line of credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial assurances are commonly provided in the form of standby letters of credit.

Accounts receivable included in the consolidated balance sheets are reflected net of our allowance for doubtful accounts. We routinely review our receivable balances to identify past due amounts and analyze the reasons such amounts have not been collected. In many instances, such delays involve billing delays and discrepancies or disputes as to the appropriate price, volumes or quality of crude oil delivered or exchanged. We also attempt to monitor changes in the creditworthiness of our customers as a result of developments related to each customer, the industry as a whole and the general economy. Based on these analyses as well as our historical experience and the facts and circumstances surrounding certain aged balances, we have established an allowance for doubtful trade accounts receivable and consider this reserve adequate; however, there is no assurance that actual amounts will not vary significantly from estimated amounts. The discovery of previously unknown facts or adverse developments affecting one of our counterparties or the industry as a whole could adversely impact our results of operations.

At December 31, 2003 and 2002, approximately 99% of net accounts receivable classified as current were less than 60 days past scheduled invoice date, and our allowance for doubtful accounts receivable classified as current totaled $0.2 million and $3.1 million, respectively. We consider these reserves adequate. At December 31, 2003 we had no accounts receivable balances or allowance for doubtful accounts classified as long-term. At December 31, 2002, approximately $11.5 million of accounts receivable ($6.5 million, net of a $5.0 million allowance) was classified as long-term. Following is a reconciliation of the changes in our allowance for doubtful accounts balances (in millions):

	December 31,		
	2003	**2002**	**2001**
Balance at beginning of year	$ 8.1	$ 8.0	$ 5.0
Applied to accounts receivable balances	(8.3)		
Charged to expense	0.4	0.1	3.0
Balance at end of year	$ 0.2	$ 8.1	$ 8.0

Inventory

Inventory primarily consists of crude oil and LPG in pipelines, storage tanks and rail cars which is valued at the lower of cost or market, with cost determined using an average cost method. In the fourth quarter of 2001, the Partnership recorded a $5.0 million noncash writedown of operating crude oil inventory to reflect prices at December 31, 2001. During 2001, the price of crude oil traded on the NYMEX averaged $25.98 per barrel. At December 31, 2001, the NYMEX crude oil price was approximately 24% lower, or $19.84 per barrel. There was no writedown of operating crude oil inventory at December 31, 2003 or 2002, as the market prices of crude oil and LPG were higher than our average cost per barrel. At December 31, 2003 and 2002, inventory consisted of (in millions):

	December 31,	
	2003	2002
Crude oil	$ 50.6	$ 53.5
LPG	53.8	28.3
Other	1.6	
	$ 106.0	$ 81.8

Property and Equipment and Pipeline Linefill

Property and equipment, net is stated at cost and consisted of the following (in millions):

	December 31,	
	2003	2002
Crude oil pipelines and facilities	$ 1,114.5	$ 909.3
Crude oil and LPG storage and terminal facilities	100.8	82.4
Trucking equipment and other	43.8	30.0
Office property and equipment	13.5	8.6
	1,272.6	1,030.3
Less accumulated depreciation	(121.6)	(77.5)
	$ 1,151.0	$ 952.8

Depreciation expense for each of the three years in the period ended December 31, 2003, was $42.4 million, $30.2 million and $21.6 million, respectively. Our policy is to depreciate property and equipment over estimated useful lives as follows:

crude oil pipelines and facilities 30 to 40 years;

crude oil and LPG storage and terminal facilities 30 to 40 years;

trucking equipment and other 5 to 15 years; and

office property and equipment 3 to 5 years

We calculate our depreciation and amortization using the straight-line method, based on estimated useful lives and salvage values of our assets. These estimates are based on various factors including age (in the case of acquired assets), manufacturing specifications, technological advances and historical data concerning useful lives of similar assets. Uncertainties that impact these estimates include changes in laws and regulations relating to restoration and abandonment requirements, economic conditions, and supply and demand in the area. When assets are put into service, we make estimates with respect to useful lives and salvage values that we believe are reasonable. However, subsequent events could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization.

Historically, adjustments to useful lives have not had a material impact on our aggregate depreciation levels from year to year.

In accordance with our capitalization policy, costs associated with acquisitions and improvements, including related interest costs, which expand our existing capacity are capitalized. For the years ended December 31, 2003, 2002 and 2001, capitalized interest was $0.5 million, $0.8 million and $0.2 million, respectively. In addition, costs required either to maintain the existing operating capacity of partially or fully depreciated assets or to extend their useful lives are capitalized and classified as maintenance capital. Repair and maintenance expenditures associated with existing assets that do not extend the useful life or expand the operating capacity are charged to expense as incurred.

Linefill and minimum working inventory requirements are recorded at lower of cost or market and consists of crude oil and LPG used to pack a pipeline such that when an incremental barrel enters a pipeline it forces a barrel out at another location as well as minimum crude oil necessary to operate our storage and terminalling facilities. At December 31, 2003, we had approximately 4.6 million barrels of crude oil and 7.7 million gallons of LPG used to maintain our minimum linefill and working inventory requirements. Proceeds from the sale and repurchase of pipeline linefill are reflected as cash flows from operating activities in the accompanying consolidated statements of cash flows.

Asset Retirement Obligation

In June 2001, the FASB issued SFAS No. 143 "Asset Retirement Obligations." SFAS 143 establishes accounting requirements for retirement obligations associated with tangible long-lived assets, including (1) the time of the liability recognition, (2) initial measurement of the liability, (3) allocation of asset retirement cost to expense, (4) subsequent measurement of the liability and (5) financial statement disclosures. SFAS 143 requires that the cost for asset retirement should be capitalized as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. Effective January 1, 2003, we adopted SFAS 143, as required. Determination of the amounts to be recognized upon adoption is based upon numerous estimates and assumptions, including future retirement costs, future inflation rates and the credit-adjusted risk-free interest rate. The majority of our assets, primarily related to our pipeline operations segment, have obligations to perform remediation and, in some instances, removal activities when the asset is abandoned. However, the fair value of the asset retirement obligations cannot be reasonably estimated, as the settlement dates are indeterminate. We will record such asset retirement obligations in the period in which we can reasonably determine the settlement dates. The adoption of this statement did not have a material impact on our financial position, results of operations or cash flows.

Impairment of Long-Lived Assets

Long-lived assets with recorded values that are not expected to be recovered through future cash flows are written-down to estimated fair value in accordance with SFAS No. 144 "Accounting for the Impairment or Disposal of Long-Lived Assets," as amended. Under SFAS 144, an asset shall be tested for impairment when events or circumstances indicate that its carrying value may not be recoverable. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the carrying value exceeds the sum of the undiscounted cash flows, an impairment loss equal to the amount the carrying value exceeds the fair value of the asset is recognized. Fair value is generally determined from estimated discounted future net cash flows. We adopted SFAS 144 on January 1, 2002, and there have been no events or circumstances indicating that the carrying value of any of our assets may not be recoverable.

Other Assets

Other assets, net consist of the following (in millions):

	December 31,	
	2003	2002
Goodwill	$ 39.4	$ 12.9
Deposit on Capline Acquisition	15.8	
Debt issue costs	12.1	21.6
Investment in affiliate	7.8	8.0
Long term receivable, net		6.5
Fair value of derivative instruments	5.9	2.6
Intangible assets (contracts)	2.6	2.4
Other	7.1	2.6
	90.7	56.6
Less accumulated amortization	(1.7)	(8.3)
	$ 89.0	$ 48.3

Goodwill is recorded as the amount of the purchase price in excess of the fair value of certain assets purchased. At December 31, 2003, we recorded additional consideration related to the deferred portion of the purchase price in the CANPET acquisition (See Note 3). The entire amount of this consideration was recorded as additional goodwill. In accordance with SFAS No. 142, "Goodwill and Other Intangible Assets," which we adopted January 1, 2002, we test goodwill and other intangible assets periodically to determine whether an impairment has occurred. Goodwill is tested for impairment at a level of reporting referred to as a reporting unit. If the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is considered not impaired. An impairment loss is recognized for intangibles if the carrying amount of an intangible asset is not recoverable and its carrying amount exceeds its fair value. As of December 31, 2003, no impairment has occurred.

Costs incurred in connection with the issuance of long-term debt and amendments to our credit facilities are capitalized and amortized using the straight-line method over the term of the related debt. Use of the straight-line method does not differ materially from the "effective interest" method of amortization. During the fourth quarter of 2003, we replaced our senior secured credit facilities with new senior unsecured credit facilities and we completed the sale of $250 million of 5.625% senior notes (See Note 6). We capitalized approximately $5.1 million of costs associated with those transactions. Also, in conjunction with the credit facility refinancing, we incurred a non-cash charge of approximately $3.3 million attributable to a loss on the early extinguishment of debt (included in Interest income and other, net on the Consolidated Statement of Operations). The loss consists of unamortized debt issue costs written off as a result of the completion of the new credit facility. In addition, we wrote off approximately $11.3 million of fully amortized debt issue costs and the related accumulated amortization.

Amortization of other assets for each of the three years in the period ended December 31, 2003, was $4.4 million, $3.9 million and $2.7 million, respectively.

Environmental Matters

We expense or capitalize, as appropriate, environmental expenditures. We expense expenditures that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation. We record environmental liabilities when environmental assessments and/or remedial efforts are probable and we can reasonably estimate the costs. Generally, our recording of these accruals coincides with our completion of a feasibility study or our commitment to a formal plan of action.

Income and Other Taxes

Except as noted below, no provision for U.S. federal or Canadian income taxes related to our operations is included in the accompanying consolidated financial statements, because as a partnership we are not subject to federal, state or provincial income tax and the tax effect of our activities accrues to the unitholders. Net earnings for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under the partnership agreement. Individual unitholders will have different investment bases depending upon the timing and price of acquisition of partnership units. Further, each unitholder's tax accounting, which is partially dependent upon the unitholder's tax position, may differ from the accounting followed in the consolidated financial statements. Accordingly, there could be significant differences between each individual unitholder's tax bases and the unitholder's share of the net assets reported in the consolidated financial statements. We do not have access to information about each individual unitholder's tax attributes, and the aggregate tax basis cannot be readily determined. Accordingly, we do not believe that in our circumstances, the aggregate difference would be meaningful information.

The Partnership's Canadian operations are conducted through an operating limited partnership, of which our wholly owned subsidiary PMC (Nova Scotia) Company is the general partner. For Canadian tax purposes, the general partner is taxed as a corporation, subject to income taxes and a capital-based tax at federal and provincial levels. For 2003 and 2002, the income tax was not material and the capital-based tax was approximately $0.4 million (U.S.) and $0.5 million (U.S), respectively. In addition, interest payments made by Plains Marketing Canada, L.P. on its intercompany loan from Plains Marketing, L.P. are subject to a 10% Canadian withholding tax, which for 2003 and 2002 totaled $0.4 million and $0.5 million, respectively, and is recorded in other expense.

In addition to federal income taxes, owners of our common units may be subject to other taxes, such as state and local and Canadian federal and provincial taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that may be imposed by the various jurisdictions in which we do business or own property. A unitholder may be required to file Canadian federal income tax returns, pay Canadian federal and provincial income taxes, file state income tax returns and pay taxes in various states.

Derivative Instruments and Hedging Activities

We utilize various derivative instruments to (i) manage our exposure to commodity price risk, (ii) engage in a controlled trading program, (iii) manage our exposure to interest rate risk and (iv) manage our exposure to currency exchange rate risk. Beginning January 1, 2001, we record all derivative instruments on the balance sheet as either assets or liabilities measured at their fair value under the provisions of SFAS 133, "Accounting for Derivative Instruments and Hedging Activities" as amended by SFAS 137 and SFAS 138 (collectively "SFAS 133"). At adoption, and in accordance with the transition provisions of SFAS 133, we recorded a loss of $8.3 million in Other Comprehensive Income ("OCI"), representing the cumulative effect of an accounting change to recognize, at fair value, all cash flow derivatives. We also recorded a noncash gain of $0.5 million in earnings as a cumulative effect adjustment. SFAS 133 requires that changes in derivative instruments fair value be recognized currently in earnings unless specific hedge accounting criteria are met, in which case, changes in fair value are deferred to OCI and reclassified into earnings when the underlying transaction affects earnings. Accordingly, changes in fair value are included in the current period for (i) derivatives characterized as fair value hedges, (ii) derivatives that do not qualify for hedge accounting and (iii) the portion of cash flow hedges that is not highly effective in offsetting changes in cash flows of hedged items.

Net Income Per Unit

Basic and diluted net income per unit is determined by dividing net income after deducting the amount allocated to the general partner interest, (including its incentive distribution in excess of its 2% interest), by the weighted average number of outstanding limited partner units, including common units and subordinated units. Partnership income is first allocated to the general partner based on the amount of incentive distributions. The remainder is then allocated between the limited partners and general partner based on percentage ownership in the Partnership. Other comprehensive income is allocated based on the same effective percentages. The following table sets forth the computation of basic and diluted net income per limited partner unit for 2003, 2002 and 2001 (in millions, except per unit amounts). The net income available to limited partners and the weighted average limited partner units outstanding have been adjusted for the impact of the contingent equity issuance related to the CANPET acquisition for the calculation of diluted net income per limited partner unit (See Note 3).

	Year Ended December 31,		
	2003	**2002**	**2001**
	(in millions, except per unit data)		
Net income	$ 59.4	$ 65.3	$ 44.2
Less:			
General partner incentive distributions	(4.9)	(3.1)	(1.1)
General partner 2% ownership	(1.1)	(1.3)	(0.9)
Numerator for basic earnings per limited partner unit:			
Net income available for common unitholders	53.4	60.9	42.2
Effect of dilutive securities:			
Increase in general partner's incentive distribution Contingent equity issuance	(0.1)		
Numerator for diluted earnings per limited partner unit	$ 53.3	$ 60.9	$ 42.2
Denominator:			
Denominator for basic earnings per limited partner unit weighted average number of limited partner units	52.7	45.5	37.5
Effect of dilutive securities:			
Contingent equity issuance	0.7		
Denominator for diluted earnings per limited partner unit weighted average number of limited partner units	53.4	45.5	37.5
Basic net income per limited partner unit	$ 1.01	$ 1.34	$ 1.13
Diluted net income per limited partner unit	$ 1.00	$ 1.34	$ 1.13

Note 3 Acquisitions

The following acquisitions were accounted for using the purchase method of accounting and the purchase price was allocated in accordance with such method. In addition, we adopted SFAS No. 141, "Business Combinations" in 2001 and followed the provisions of that statement for all business combinations initiated after June 30, 2001.

Significant Acquisitions

Shell West Texas Assets

On August 1, 2002, we acquired from Shell Pipeline Company LP and Equilon Enterprises LLC interests in approximately 2,000 miles of gathering and mainline crude oil pipelines and approximately 8.9 million barrels (net to our interest) of above-ground crude oil terminalling and storage assets in West Texas (the "Shell acquisition"). The results of operations and assets from this acquisition have been included in our consolidated financial statements and in our pipeline operations segment since that date. The primary assets included in the transaction were interests in the Basin Pipeline System, the Permian Basin Gathering System and the Rancho Pipeline System. These assets complement our existing asset infrastructure in West Texas and represent a transportation link to Cushing, Oklahoma, where we are a provider of storage and terminalling services. The total purchase price of $324.4 million consisted of (i) $304.0 million in cash, which was borrowed under our revolving credit facility, (ii) approximately $9.1 million related to the settlement of pre-existing accounts receivable and inventory balances and (iii) approximately $11.3 million of estimated transaction and closing costs. The entire purchase price was allocated to property and equipment.

CANPET Energy Group Inc.

In July 2001, we acquired the assets of CANPET Energy Group Inc. ("CANPET"), a Calgary-based Canadian crude oil and LPG marketing company, 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. In addition, an amount will be paid equivalent to the distributions that would have been paid on the common units assuming (i) the deferred portion of the purchase price was paid in common units and (ii) they had been outstanding since the acquisition date. As of December 31, 2003, we determined that it was beyond a reasonable doubt that the performance standards were met and we recorded additional consideration of $24.3 million (see Note 7) resulting in aggregate consideration of $73.9 million. The deferred consideration was recorded as additional goodwill.

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 LPG's. 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. Initial financing for the acquisition was provided through borrowings under our credit facility.

The purchase price, as adjusted post-closing, 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
Total	$	73.9

Murphy Oil Company Ltd. Midstream Operations

In May 2001, we closed 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 (the "Murphy acquisition"), including financing and transaction costs. Initial financing for the acquisition was provided through borrowings under our credit facilities. The purchase included $6.5 million for excess inventory in the pipeline systems. The principal assets acquired include approximately 560 miles of crude oil and condensate transmission 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 the acquisition, the volume under the contract was 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
Net working capital items		2.0
Other property and equipment		0.5
Other assets, including debt issue costs		0.3
Total	$	158.4

Other Acquisitions

2003 Acquisitions

During 2003, we completed ten acquisitions for aggregate consideration totaling approximately $159.5 million. The aggregate consideration includes cash paid, estimated transaction costs, assumed liabilities and estimated near-term capital costs. These acquisitions included mainline crude oil pipelines, crude oil gathering lines, terminal and storage facilities, and an underground LPG storage facility. The aggregate purchase price was allocated as follows (in million):

Crude oil pipelines and facilities	$ 138.0
Crude oil and LPG storage facilities	7.3
Trucking equipment and other	7.8
Office property and equipment	1.2
Pipeline Linefill	4.7
Goodwill	0.5
	$ 159.5

2002 Acquisitions

During 2002, in addition to the Shell acquisition, we completed two acquisitions for aggregate consideration totaling approximately $15.9 million including transaction costs. These acquisitions include crude oil pipeline, gathering and marketing assets and a 22% equity interest in a pipeline company. With the exception of $1.3 million that was allocated to goodwill, the aggregate purchase price was allocated to property and equipment.

2001 Acquisition

In December 2001, in addition to the CANPET and Murphy acquisitions, we acquired 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 includes a crude oil pipeline and approximately 21,500 barrels of crude oil storage capacity located along the system as well as a truck terminal.

Note 4 Asset Dispositions

Shutdown of Rancho Pipeline System

We acquired 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, we completed transactions whereby we transferred all of our ownership interest in approximately 240 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. The remaining portion will either be sold or salvaged. No gain or loss has been recorded on the shutdown of the Rancho System or these transactions.

Other Dispositions

During 2003 and 2002, we sold various other property and equipment for proceeds totaling approximately $8.5 million and $1.4 million, respectively. A gain of approximately $0.6 million was recognized in 2003 and no gain or loss was recognized in 2002. In December 2001, we sold excess communications equipment and recognized a gain of $1.0 million.

Note 5 Industry Credit Markets

Throughout the latter part of 2001 and all of 2002, there have been 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 has been especially impacted by these developments. Accordingly, we are exposed to an increased level of direct and indirect counterparty credit and performance risk.

The majority of our credit extensions and therefore our accounts receivable relate to our gathering and marketing activities that can generally be described as high volume and low margin activities. In our credit approval process, we must determine the amount, if any, of the line of credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial assurances are commonly provided to us in the form of standby letters of credit, advance cash payments or "parental" guarantees. At December 31, 2003, we had received approximately $44.0 million of advance cash payments and prepayments from third parties to mitigate credit risk.

Note 6 Debt

Short-term debt consists of the following (in millions):

	December 31,	
	2003	2002
Senior secured hedged inventory borrowing facility bearing interest at a rate of 1.9% at December 31, 2003	$ 100.5	$
Senior unsecured $425 million domestic revolving credit facility working capital borrowings, bearing interest at a rate of 4.0% at December 31, 2003[(1)]	25.3	
Senior secured letter of credit and borrowing facility bearing interest at a rate of 3.4% at December 31, 2002		97.7
Other	1.5	1.5
Total short-term debt and current maturities of long-term debt	$ 127.3	$ 99.2

(1) At December 31, 2003, we have classified $25.3 million of borrowings under our Senior unsecured domestic revolving credit facility as short-term. These borrowings are designated as working capital borrowings under this facility and primarily are for hedged LPG inventory and New York Mercantile Exchange ("NYMEX") margin deposits and must be repaid within one year.

Long-term debt consists of the following (in millions):

	December 31, 2003	December 31, 2002
5.63% senior notes due December 2013, net of unamortized discount of $0.7 million	$ 249.3	$
7.75% senior notes due October 2012, net of unamortized discount of $0.3 million and $0.4 million at December 31, 2003 and 2002, respectively	199.7	199.6
Senior unsecured $170 million Canadian revolving credit facility, bearing interest at a rate of 2.17% at December 31, 2003	70.0	
Senior secured domestic revolving credit facility, bearing interest at a rate of 4.8% at December 31, 2002		10.4
Senior secured term B loan, bearing interest at a rate of 3.9% at December 31, 2002		198.0
Senior secured term loan, bearing interest at a rate of 3.9% at December 31, 2002		99.0
$30 million Canadian senior secured revolving credit facility, bearing interest at a rate of 5.0% at December 31, 2002		2.7
Total long-term debt[(1),(2)]	$ 519.0	$ 509.7

(1) At December 31, 2002, we classified $9 million of term loan payments due in 2003 as long term due to our intent and ability to refinance those maturities using the revolving facility.

(2) At December 31, 2003, we have classified $25.3 million of borrowings under our Senior unsecured domestic revolving credit facility as short-term. These borrowings are designated as working capital borrowings under this facility and primarily are for hedged LPG inventory and NYMEX margin deposits and must be repaid within one year.

Credit Facilities

During November 2003, we refinanced our bank credit facilities with new senior unsecured credit facilities totaling $750 million and a $200 million uncommitted facility for the purpose of financing hedged crude oil. The $750 million of new facilities consist of:

- a four-year, $425 million U.S. revolving credit facility;
- a 364-day, $170 million Canadian revolving credit facility with a five-year term-out option;
- a four-year, $30 million Canadian working capital revolving credit facility; and
- a 364-day, $125 million revolving credit facility.

All of the facilities with the exception of the $200 million hedged inventory facility are unsecured. The $200 million hedged inventory 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 from the proceeds from the sale of such inventory.

Senior Notes

During December 2003, we completed the sale of $250 million of 5.625% senior notes due in December 2013. The notes were issued by Plains All American Pipeline, L.P. and a 100% owned consolidated 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 which are minor.

During September 2002, we completed the sale of $200 million of 7.75% senior notes due in October 2012. The notes were issued by Plains All American Pipeline, L.P. and a 100% owned consolidated finance subsidiary (neither of which have independent assets or operations) at a discount of $0.4 million, resulting in an effective interest rate of 7.78%. Interest payments are due on April 15 and October 15 of each year. The notes are fully and unconditionally guaranteed, jointly and severally, by all of our existing 100% owned subsidiaries, except for subsidiaries which are minor.

Covenants and Compliance

Our credit facilities, the indenture governing the 5.625% senior notes and the indenture governing the 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:

- a debt coverage ratio which will not be greater than: 4.50 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); and
- an interest coverage ratio that is not less than 2.75 to 1.0.

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 our partnership agreement. We are in compliance with the covenants contained in our credit facilities and indentures.

Letters of Credit

As is customary in our industry, and in connection with our crude oil marketing, we provide certain suppliers and transporters with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the crude oil is purchased. Generally, these letters of credit are issued for up to seventy-day periods and are terminated upon completion of each transaction. At December 31, 2003 and 2002, we had outstanding letters of credit of approximately $57.9 million and $52.5 million, respectively. In addition to changes in the level of activity and other factors, the amount of letters of credit outstanding varies based on NYMEX crude oil prices, which were $32.52 per barrel and $29.45 per barrel at December 31, 2003 and 2002, respectively.

Maturities

The weighted average life of our long-term debt outstanding at December 31, 2003, was approximately 9 years and all balances mature in 2009 or later.

Note 7 Partners' Capital and Distributions

Units Outstanding

Partners' capital at December 31, 2003 consists of (1) 50,809,746 common units, including 1,307,190 Class B common units, representing a 85.4% effective aggregate ownership interest in the Partnership and its subsidiaries, (after giving affect to the general partner interest), (2) 7,522,214 subordinated units representing a 12.6% effective aggregate ownership interest in the Partnership and its subsidiaries (after giving affect to the general partner interest) and (3) a 2% general partner interest.

Class B Common Units

The Class B common units are initially pari passu with common units with respect to distributions, and are convertible into common units upon approval of a majority of the common unitholders. The Class B unitholders may request that we call a meeting of common unitholders to consider approval of the conversion of Class B units into common units. If the approval of a conversion by the common unitholders is not obtained within 120 days of a request, each Class B common unitholder will be entitled to receive distributions, on a per unit basis, equal to 110% of the amount of distributions paid on a common unit, with such distribution right increasing to 115% if such approval is not secured within 90 days after the end of the 120-day period. Except for the vote to approve the conversion, Class B common units have the same voting rights as the common units.

Subordinated Units and Conversion

The subordinated units have a debit balance in Partners' Capital of approximately $39.9 million at December 31, 2003. The debit balance is the result of several different factors including: (i) a low initial capital balance in connection with the formation of the partnership as a result of a low carry-over book basis in the assets contributed to the Partnership at the date of formation, (ii) a significant net loss in 1999 and (iii) distributions to unitholders that have exceeded net income allocated to unitholders each period. Additionally, the capital balances of the common unitholders and the General Partner have increased periodically as additional units have been sold and as the General Partner has made additional capital contributions associated with those offerings. The subordinated unitholders are not required to make any additional contributions associated with those offerings of common units. No additional Subordinated Units were issued after the initial issuance.

Pursuant to the terms of our Partnership Agreement and having satisfied the financial tests contained therein, in November 2003, 25% of the Subordinated Units converted to Common Units on a one-for-one basis. In February 2004, all of the remaining Subordinated Units converted to Common Units on a one-for-one basis.

General Partner Incentive Distributions

Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, generally the general partner is entitled, without duplication, to 15% of amounts we distribute in excess of $0.450 per unit ("MQD"), 25% of the amounts we distribute in excess of $0.495 per unit and 50% of amounts we distribute in excess of $0.675 per unit (referred to as "incentive distributions"). Cash distributions on our outstanding units and the portion of the distributions representing an excess over the MQD were as follows:

	Year					
	2003		2002		2001	
	Distribution	Excess over MQD	Distribution	Excess over MQD	Distribution	Excess over MQD
First Quarter	$ 0.5500	$ 0.1000	$ 0.5250	$ 0.0750	$ 0.4750	$ 0.0250
Second Quarter	$ 0.5500	$ 0.1000	$ 0.5375	$ 0.0875	$ 0.5000	$ 0.0500
Third Quarter	$ 0.5500	$ 0.1000	$ 0.5375	$ 0.0875	$ 0.5125	$ 0.0625
Fourth Quarter	$ 0.5625	$ 0.1125	$ 0.5375	$ 0.0875	$ 0.5125	$ 0.0625

Distributions

We will distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established by our general partner for future requirements.

During 2003, we paid distributions of approximately $121.8 million ($2.19 on a per unit basis), with approximately $92.7 million paid to our common unitholders, $21.9 million paid to our subordinated unitholders and $2.3 million and $4.9 million paid to our general partner for its general partner and incentive distribution interests, respectively.

During 2002, we paid distributions of approximately $99.8 million ($2.11 on a per unit basis), with approximately $73.6 million paid to our common unitholders, $21.1 million paid to our subordinated unitholders and $2.0 million and $3.1 million paid to our general partner for its general partner and incentive distribution interests, respectively.

During 2001, we paid distributions of approximately $75.9 million ($1.95 on a per unit basis), with approximately $53.8 million paid to our common unitholders, $19.5 million paid to our subordinated unitholders and $1.5 million and $1.1 million paid to our general partner for its general partner and incentive distribution interests, respectively.

On January 22, 2004, we declared a cash distribution of $0.5625 per unit on our outstanding common units, Class B common units and subordinated units. The distribution was paid on February 13, 2004, to unitholders of record on February 3, 2004, for the period October 1, 2003, through December 31, 2003. The total distribution paid was approximately $35.2 million, with approximately $28.7 million paid to our common unitholders, $4.2 million paid to our subordinated unitholders and $0.7 million and $1.6 million paid to our general partner for its general partner and incentive distribution interests, respectively.

Equity Offerings

In December 2003, we completed a public offering of 2,840,800 common units for $31.94 per unit. The offering resulted in gross proceeds of approximately $90.7 million from the sale of the units and approximately $1.8 million from our general partner's proportionate capital contribution. Total costs associated with the offering, including underwriter fees and other expenses, were approximately $4.1 million. Net proceeds of approximately $88.4 million were used to reduce outstanding borrowings under our revolving credit facility.

In September 2003, we completed a public offering of 3,250,000 common units for $30.91 per unit. The offering resulted in gross proceeds of approximately $100.5 million from the sale of the units and approximately $2.1 million from our general partner's proportionate capital contribution. Total costs associated with the offering, including underwriter fees and other expenses, were approximately

$4.5 million. Net proceeds of approximately $98.0 million were used to reduce outstanding borrowings under the domestic revolving credit facility and reduce the principal balance on our Senior secured term B loan.

In March 2003, we completed a public offering of 2,645,000 common units for $24.80 per unit. The offering resulted in gross proceeds of approximately $65.6 million from the sale of the units and approximately $1.3 million from our general partner's proportionate capital contribution. Total costs associated with the offering, including underwriter fees and other expenses, were approximately $3.0 million. Net proceeds of approximately $63.9 million were used to reduce outstanding borrowings under the domestic revolving credit facility.

In August 2002, we completed a public offering of 6,325,000 common units for $23.50 per unit. The offering resulted in cash proceeds of approximately $148.6 million from the sale of the units and approximately $3.0 million from our general partner's proportionate capital contribution. Total costs associated with the offering, including underwriter fees and other expenses, were approximately $6.6 million. Net proceeds of approximately $145.0 million were used to reduce outstanding borrowings under the domestic revolving credit facility.

In May 2001, we completed a public offering of 3,966,700 common units. Total net cash proceeds from the offering, including our former general partner's proportionate contribution, were approximately $100.7 million. In addition, in October 2001, we completed a public offering of 4,900,000 common units. Net cash proceeds from the offering, including our general partner's proportionate contribution, were approximately $126.0 million. The net proceeds were used to repay borrowings under our revolving credit facility, a portion of which was used to finance our Canadian acquisitions.

Contingent Equity Issuance

In connection with the CANPET acquisition in July 2001, a portion of the purchase price, payable in common units, was deferred subject to various performance objectives being met. These objectives have been met as of December 31, 2003, and the deferred amount is payable on April 30, 2004. The number of common units issued in satisfaction of the deferred payment will depend upon the average trading price of our common units for a ten-day trading period prior to the payment date and the Canadian and U.S. dollar exchange rate on the payment date. In addition, an amount will be paid equivalent to the distributions that would have been paid on the common units had they been outstanding since the acquisition was consummated. At our option, the deferred payment may be paid in cash rather than the issuance of units. Assuming the entire obligation is satisfied with common units, based on the foreign exchange rate in effect at December 31, 2003, (1.30 to 1 Canadian dollar to U.S. dollar exchange rate) and an estimated $33.35 per unit price, approximately 613,000 units would be issued and approximately $3.9 million would be paid related to distributions. We currently anticipate that one-third of the contingent purchase price and all of the amount related to past distributions will be paid in cash and the remainder will be settled with approximately 409,000 common units.

Note 8 Derivatives and Financial Instruments

We utilize various derivative instruments to (i) manage our exposure to commodity price risk, (ii) engage in a controlled trading program, (iii) manage our exposure to interest rate risk and (iv) manage our exposure to currency exchange rate risk. Our risk management policies and procedures are designed to monitor interest rates, currency exchange rates, NYMEX and over-the-counter positions, and physical volumes, grades, locations and delivery schedules to ensure that our hedging activities address our market risks. We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategy for undertaking the hedge. We calculate hedge effectiveness on a quarterly basis. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument's effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items.

Summary of Financial Impact

The following is a summary of the financial impact of the derivative instruments and hedging activities discussed below. At December 31, 2003, the balance sheet includes assets of $27.9 million ($22.0 million current), liabilities of $28.1 million ($17.1 million current) and related unrealized losses deferred to OCI of $1.6 million related to open derivative positions. Revenues for the year ended December 31, 2003 include a noncash gain of $0.4 million ($1.4 million noncash gain net of the reversal of the prior period fair value adjustment related to contracts that settled during the current year). Our hedge-related assets and liabilities are included in other current and non-current assets and liabilities in the consolidated balance sheet. In addition, during the fourth quarter of 2003 we terminated and cash settled three interest-rate risk hedging instruments for approximately $6.2 million. The net deferred loss related to these instruments was deferred in OCI and is being amortized into interest expense over the original terms of the terminated instruments (approximately fifty percent over three years and the remaining fifty percent over ten years).

As of December 31, 2003, the total amount of deferred net losses recorded in OCI are expected to be reclassified to future earnings, contemporaneously with the related physical purchase or delivery of the underlying commodity or payments of interest. During the periods ended December 31, 2003 and 2002, no amounts were reclassified to earnings from OCI in connection with forecasted transactions that were no longer considered probable of occurring. Based on the aggregate amounts deferred in OCI at December 31, 2003, a net loss of $0.4 million will be reclassified to earnings in the next twelve months and the remainder by 2013. Since a portion of these amounts are based on market prices at the current period end, actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

The following sections discuss our risk management activities in the indicated categories.

Commodity Price Risk Hedging

We hedge our exposure to price fluctuations with respect to crude oil and LPG in storage, and expected purchases, sales and transportation of these commodities. The derivative instruments 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 for a discussion of the mitigation of credit risk). In accordance with SFAS 133, these derivative instruments are recorded in the balance sheet as assets or liabilities at their fair values. The majority of our commodity price risk derivative instruments qualify for hedge accounting as cash flow hedges. Therefore, the corresponding changes in fair value for the effective portion of the hedge are deferred in OCI and recognized in revenues or purchases in the periods during which the underlying physical transactions occur. At December 31, 2003 there was an unrealized gain of $2.1 million deferred in OCI related to our commodity price risk activities. All of these deferred positions mature by December 2004. An unrealized gain of $1.2 million related to these activities was deferred in OCI at December 31, 2002. For each of the three years ended December 31, 2003, income of $0.5 million, $0.3 million and $0.4 million (excluding the impact of the adoption of SFAS 133), respectively, was included in revenues due to changes in the fair value of derivatives that do not qualify for hedge accounting and the portion of cash flow hedges that are not highly effective. We have determined that our physical purchase and sale agreements qualify for the normal purchase and sale exclusion and thus are not subject to SFAS 133.

Controlled Trading Program

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 and an aggregate of 250,000 barrels of LPG. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. In accordance with SFAS 133, these derivative instruments are recorded in the balance sheet as assets or liabilities at their fair value, with the changes in fair value recorded net in revenues. There were no open positions under this program at December 31, 2003 and 2002. The realized earnings impact related to these activities for the years ended December 31, 2003, 2002 and 2001, was a loss of $0.1 million, income of $0.1 million and a loss of $0.9 million, respectively.

Interest Rate Risk Hedging

We also utilize various products, such as interest rate swaps, collars and treasury locks to hedge interest obligations on specific debt issuances, including anticipated debt issuances. All of these instruments are placed with large creditworthy financial institutions.

At December 31, 2003, there was one interest rate swap outstanding with an aggregate notional principal amount of $50 million. The interest rate swap is based on LIBOR rates and provides for a LIBOR rate of 4.3% expiring in March 2004. Interest on the underlying debt being hedged is based on LIBOR plus a margin.

The instruments outstanding at December 31, 2002, consisted of interest rate swaps and a treasury lock with an aggregate notional principal amount of $150 million. The interest rate swaps were based on LIBOR rates and provided for a LIBOR rate of 5.1% for a $50.0 million notional principal amount expiring October 2006 and a LIBOR rate of 4.3% for a $50.0 million notional principal amount expiring March 2004. Interest on the underlying debt that was hedged was based on LIBOR plus a margin. During 2002, we entered into a treasury lock in anticipation of the issuance of our 7.75% senior notes due October 2012 and potential subsequent add-on thereto. A treasury lock is a financial derivative instrument that enables the company to lock in the U.S. Treasury Note rate. The treasury lock had a notional principal amount of $50.0 million and an effective interest rate of 4.60%. The treasury lock matured in January 2003, was extended to March 2003 with an effective interest rate of 4.68%, was converted to a forward starting swap and was subsequently unwound in conjunction with the issuance of our 5.625% Senior Notes.

The instruments outstanding at December 31, 2003 and 2002 qualify for hedge accounting as cash flow hedges in accordance with SFAS 133. The effective portion of changes in fair values of these hedges is recorded in OCI until the related hedged item impacts earnings. At December 31, 2003, and 2002, there was a $6.5 million unrealized loss and a $9.6 million unrealized loss, respectively, deferred in OCI related to our interest rate risk activities. As discussed above, approximately $6.1 million of the loss deferred in OCI at December 31, 2003, relates to instruments terminated and cash settled during 2003. During 2003 and 2002, there were no amounts recognized in earnings related to hedge ineffectiveness.

Currency Exchange Rate Risk Hedging

Because a significant portion of our Canadian business is conducted in Canadian dollars (CAD), we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. 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 and at December 31, 2002, $2.7 million of our long-term debt was denominated in Canadian dollars ($4.3 million CAD based on a Canadian dollar to U.S. dollar exchange rate of 1.58 to 1). All of these financial instruments are placed with large creditworthy financial institutions.

At December 31, 2003, we had forward exchange contracts that allow us to exchange approximately $2.0 million Canadian for at least $1.5 million U.S. quarterly during 2004 and approximately $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 approximately 1.33 to 1 and 1.34 to 1, respectively). In addition, at December 31, 2003, we also had cross currency swap contracts for an aggregate notional principal amount of $23.0 million, effectively converting this amount of our U.S. dollar denominated debt to $35.6 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. on May 2004 and May 2005 and has a final maturity in May 2006 ($19.0 million U.S.).

At December 31, 2002, we had forward exchange contracts and forward extra option contracts that allow us to exchange $3.0 million Canadian for at least $1.9 million U.S. quarterly during 2003 (based on a Canadian dollar to U.S. dollar exchange rate of 1.54 to 1). At December 31, 2002, we also had cross currency swap contracts for an aggregate notional principal amount of $24.8 million, effectively converting this amount of our U.S. dollar denominated debt to $38.3 million of Canadian dollar debt (based on a Canadian dollar to U.S. dollar exchange rate of 1.55 to 1).

The forward exchange contracts and forward extra option contracts qualify for hedge accounting as cash flow hedges and the cross currency swaps qualify for hedge accounting as fair value hedges, both in accordance with SFAS 133. Such derivative activity resulted in an unrealized loss of $0.3 million and an unrealized gain of $0.2 million deferred in OCI related to our currency exchange rate cash flow hedges at December 31, 2003 and 2002, respectively. The earnings impact related to our currency exchange rate fair value hedges was a loss of $0.1 million for the year ended December 31, 2003 and nominal for the year ended December 31, 2002.

Fair Value of Financial Instruments

The carrying amounts and fair values of our financial instruments are as follows (in millions):

	December 31,			
	2003		2002	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
NYMEX futures	$ 7.5	$ 7.5	$ 0.6	$ 0.6
Options and swaps	$ (3.3)	$ (3.3)	$ (0.6)	$ (0.6)
Forward exchange contracts	$ (0.4)	$ (0.4)	$ 0.1	$ 0.1
Forward extra option contracts	$	$	$ 0.2	$ 0.2
Cross currency swaps	$ (4.8)	$ (4.8)	$ 0.3	$ 0.3
Treasury lock	$	$	$ (3.3)	$ (3.3)
Interest rate swaps	$ (0.4)	$ (0.4)	$ (6.3)	$ (6.3)
Short and long-term debt under credit facilities	$ 95.3	$ 95.3	$ 409.4	$ 409.4
Senior notes	$ 449.0	$ 482.9	$ 199.6	$ 209.0

As of December 31, 2003 and 2002, the carrying amounts of items comprising current assets and current liabilities approximate fair value due to the short-term maturities of these instruments. The carrying amounts of the variable rate instruments in our credit facilities approximate fair value primarily because the interest rates fluctuate with prevailing market rates, while the interest rate on the 5.625% and the 7.75% senior notes is fixed and the fair value is based on quoted market prices.

The carrying amount of our derivative financial instruments approximate fair value as these instruments are recorded on the balance sheet at their fair value under SFAS 133. Our derivative financial instruments include cross currency swaps, forward exchange and extra option contracts, interest rate swap collar and treasury lock agreements for which fair values are based on current liquidation values. We also have over-the-counter option and swap contracts for which fair values are estimated based on quoted prices from various sources such as independent reporting services, industry publications and brokers. For positions where independent quotations are not available, an estimate is provided, or the prevailing market price at which the positions could be liquidated is used. In addition, we have NYMEX futures and options for which the fair values are based on quoted market prices.

Note 9 Major Customers and Concentration of Credit Risk

Marathon Ashland Petroleum accounted for 12%, 10% and 11% of our revenues for each of the three years in the period ended December 31, 2003. No other customers accounted for 10% or more of our revenues during any of the three years. The majority of the revenues from Marathon Ashland Petroleum pertain to our gathering, marketing, terminalling and storage operations. We believe that the loss of this customer would have only a short-term impact on our operating results. There can be no assurance, however, that we would be able to identify and access a replacement market at comparable margins.

Financial instruments that potentially subject us to concentrations of credit risk consist principally of trade receivables. Our accounts receivable are primarily from purchasers and shippers of crude oil. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic, industry or other conditions. We review credit exposure and financial information of our counterparties and generally require letters of credit for receivables from customers that are not considered credit worthy, unless the credit risk can otherwise be reduced (see Note 5).

Note 10 Related Party Transactions

Reimbursement of Expenses of Our General Partner and Its Affiliates

We do not directly employ any persons to manage or operate our business. These functions are provided by employees of our general partner (or, in the case of our Canadian operations, PMC (Nova Scotia) Company). Our general partner does not receive a management fee or other compensation in connection with its management of us. We reimburse our general partner for all direct and indirect costs of services provided, including the costs of employee, officer and director compensation and benefits allocable to us, and all other expenses necessary or appropriate to the conduct of our business, and allocable to us. Our agreement provides that our general partner will determine the expenses allocable to us in any reasonable manner determined by our general partner in its sole discretion. Historically, an allocation was made for overhead associated with officers and employees who divided time between us and Plains Resources. As a result of the General Partner Transition, all of the employees and officers of the general partner devote 100% of their efforts to our business and there are no allocated expenses. Total costs reimbursed by us to our general partner in for the years ended December 31, 2003, 2002 and 2001 were approximately $88.1 million, $70.8 million and $31.3 million, respectively. Total costs reimbursed by us to our former general partner and Plains Resources were approximately $31.2 million for the year ended December 31, 2001.

Crude Oil Marketing Agreement

We are the exclusive marketer/purchaser for all of Plains Resources' and its subsidiaries' equity crude oil production. The marketing agreement with Plains Resources provides that we will purchase for resale at market prices the majority of Plains Resources' crude oil production for which we charge a fee of $0.20 per barrel. This fee is subject to adjustment every three years based on then-existing market conditions. For the years ended December 31, 2003, 2002 and 2001, we paid Plains Resources approximately $25.7 million, $247.7 million and $223.2 million, respectively, for the purchase of crude oil under the agreement, including the royalty share of production, and recognized margins of approximately $0.2 million, $1.8 million and $1.8 million from the marketing fee for the same periods, respectively. In our opinion, these purchases were made at prevailing market prices. In November 2001, the marketing agreement automatically extended for an additional three-year period. 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. We are in the process of negotiating an amended agreement to reflect the separation. As currently in effect, the marketing agreement will terminate upon a "change in control" of Plains Resources or our general partner. The recently announced buyout of Plains Resources stock would constitute a change of control; however, we received assurances prior to the initial announcement that neither Plains Resources nor the buyout group intend for the agreement to terminate.

In December 2002, Plains Resources completed a spin-off of one of its subsidiaries, Plains Exploration and Production Company ("PXP") to its shareholders. PXP is a successor participant to the Plains Resources Marketing agreement. For the year ended December 31, 2003, we paid PXP approximately $277.9 million for the purchase of crude oil under the agreement, including the royalty share of production and recognized margins of approximately $1.7 million from the marketing fee. In our opinion, these purchases were made at prevailing market prices. We are also party to a Letter Agreement with Stocker Resources, L.P. (now PXP) that provides that if the Marketing Agreement terminates before our crude oil sales agreement with Tosco Refining Co. ("Tosco") terminates, PXP will continue to sell and we will continue to purchase PXP's equity crude oil production from the Arroyo Grande field (now owned by a subsidiary of PXP) under the same terms as the Marketing Agreement until our Tosco sales agreement terminates. We are in the process of negotiating the terms of an amended agreement with PXP.

Separation Agreement

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

Due to Related Parties

The balance of amounts due to related parties at December 31, 2003 and 2002 was $27.0 million and $23.3 million, respectively, and was primarily related to crude oil purchased by us but not yet paid as of December 31 of each year.

Transaction Grant Agreements

In connection with our initial public offering, our former general partner, at no cost to us, agreed to transfer, subject to vesting, approximately 400,000 of its affiliates' common units (including distribution equivalent rights attributable to such units) to certain key officers and employees of our former general partner and its affiliates. Under these grants, the common units vested based on attaining a targeted operating surplus for a given year. Approximately 70,000 units vested in 2000, with the remainder in 2001. The value of the units and associated distribution equivalent rights that vested under the Transaction Grant Agreements for all grantees in 2001 were $5.7 million. Although we recorded noncash compensation expenses with respect to these vestings, the compensation expense incurred in connection with these grants was funded by our former general partner, without reimbursement by us.

Performance Option Plan

In connection with the General Partner Transition, the owners of the general partner (other than PAA Management, L.P.) contributed an aggregate of 450,000 subordinated units (now converted into common units) to the general partner to provide a pool of units available for the grant of options to management and key employees. In that regard, the general partner adopted the Plains All American 2001 Performance Option Plan, pursuant to which options to purchase approximately 375,000 units have been granted. These options vest in 25% increments based upon achieving quarterly distribution levels on our units of $0.525, $0.575, $0.625 and $0.675 ($2.10, $2.30, $2.50 and $2.70, annualized). The first such level was reached, and 25% of the options vested, in 2002. The options will vest in their entirety immediately upon a change in control (as defined in the grant agreements). The original purchase price under the options is $22 per subordinated unit, declining over time in an amount equal to 80% of each quarterly distribution per unit. As of February 17, 2004, the purchase price was $17.30 per unit. The terms of future grants may differ from the existing grants. Because the units underlying the plan were contributed to the general partner, we will have no obligation to reimburse the general partner for the cost of the units upon exercise of the options. At December 31, 2003 approximately 371,875 units were outstanding following the exercise of 3,125 options during 2003.

Stock Option Replacement

In connection with the General Partner Transition, certain members of the management team that had been employed by Plains Resources were transferred to the general partner. At that time, such individuals held in-the-money but unvested stock options in Plains Resources, which were subject to forfeiture because of the transfer of employment. Plains Resources, through its affiliates, agreed to substitute a contingent grant of subordinated units (or common units after conversion) with a value equal to the spread on the unvested options, with distribution equivalent rights from the date of grant. The units vest on the same schedule as the stock options would have vested. The general partner administers the vesting and delivery of the units under the grants. Because the units necessary to satisfy the delivery requirements under the grants are provided by Plains Resources, we have no obligation to reimburse the general partner for the cost of such units.

Benefit Plan

A subsidiary of Plains Resources was, until June 8, 2001, our general partner. On that date, such entity transferred the general partner interest to our current general partner, which effective July 1, 2001, maintains a 401(k) defined contribution plan whereby it matches 100% of an employee's contribution (subject to certain limitations in the plan). For the years ended December 31, 2003 and 2002, the defined contribution plan expense was approximately $2.6 million and $2.1 million, respectively. For the period July 1 through December 31, 2001, defined contribution plan expense was approximately $1.1 million.

Prior to July 1, 2001, Plains Resources maintained a 401(k) defined contribution plan whereby it matched 100% of an employee's contribution (subject to certain limitations in the plan), with matching contributions being made 50% in cash and 50% in common stock of Plains Resources (the number of shares for the stock match being based on the market value of the common stock at the time the shares were granted). For the period January 1 through June 30, 2001, defined contribution plan expense was $1.0 million.

Note 11 Long-Term Incentive Plans

Our general partner has adopted the Plains All American GP LLC 1998 Long-Term Incentive Plan (the "LTIP") for employees and directors of our general partner and its affiliates who perform services for us. The LTIP consists of two components, a restricted ("phantom") unit plan and a unit option plan. The LTIP currently permits the grant of phantom units and unit options covering an aggregate of 1,425,000 common units. The plan is administered by the Compensation Committee of our general partner's board of directors. Our general partner's board of directors in its discretion may terminate the LTIP at any time with respect to any common units for which a grant has not yet been made. Our general partner's board of directors also has the right to alter or amend the LTIP or any part of the plan from time to time, including, subject to any applicable NYSE listing requirements, increasing the number of common units with respect to which awards may be granted; provided, however, that no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of such participant.

Restricted Unit Plan. A restricted unit is a "phantom" unit that entitles the grantee to receive, upon the vesting of the phantom unit, a common unit (or cash equivalent, depending on the terms of the grant). As of December 31, 2003, aggregate outstanding grants of approximately 1,003,000 have been made to employees, officers and directors of our general partner. As discussed in more detail below, a substantial number of phantom units have recently vested or are expected to vest in the first half of 2004. As of February 17, 2004, giving effect to vested grants, grants of approximately 684,000 unvested phantom units remain outstanding to employees, officers and directors of our general partner. As discussed below, a substantial portion of these phantom units are expected to vest in May 2004. The Compensation Committee may, in the future, make additional grants under the plan to employees and directors containing such terms as the Compensation Committee shall determine.

If a grantee terminates employment or membership on the board for any reason, the grantee's phantom units will be automatically forfeited unless, and to the extent, the Compensation Committee provides otherwise. Common units to be delivered upon the vesting of rights may be common units acquired by our general partner in the open market or in private transactions, common units already owned by our general partner, or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the cost incurred in acquiring common units. In addition, the Partnership may issue up to 975,000 new common units to satisfy delivery obligations under the grants, less any common units issued upon exercise of unit options under the plan (see below). If we issue new common units upon vesting of the phantom units, the total number of common units outstanding will increase. The Compensation Committee, in its discretion, may grant tandem distribution equivalent rights with respect to phantom units.

The phantom units (other than director grants) granted during the subordination period were subject to the basic restriction that vesting could take place only after and in proportion to any conversion of subordinated units into common units. Certain grants were subject to additional vesting criteria, primarily related to the Partnership's performance. In November 2003, 25% of the outstanding subordinated units converted on a one-for-one basis into common units and the remainder of our subordinated units converted into common units in February 2004. As a result, approximately 35,000 phantom units vested in November 2003, approximately 326,000 phantom units vested in February 2004, and we anticipate that approximately 473,000 additional phantom units will vest in May 2004, subject to the satisfaction of service period requirements. Under generally accepted accounting principles, we are required to recognize an expense when it is considered probable that the financial tests for conversion of subordinated units and required distribution levels will be met and that the phantom units will vest. As of December 31, 2003, we had recorded approximately $28.8 million of compensation expense for the units that vested during 2003 and those that we concluded probable of vesting during 2004. The compensation expense recorded is based upon the actual amounts paid in 2003, or for the unpaid portion, an estimated market price of $33.35 per unit, our share of employment taxes and other related costs.

During 2003, we paid cash in lieu of issuing units for approximately 7,500 of the phantom units that vested during the year and issued approximately 18,000 common units (after netting for taxes). For those units that vested in February 2004, we paid cash in lieu of issuing units for approximately 104,000 of the phantom units and issued approximately 138,000 new common units (after netting for taxes) in connection with such vesting. We anticipate paying cash for approximately 201,000 of the phantom units expected to vest in May 2004, as well as issuing approximately 181,000 new common units (after netting for taxes) in connection with such vesting.

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

In 2000, the three non-employee directors of our former general partner were each granted 5,000 phantom units. These units vested in connection with the consummation of the General Partner Transition. Additional grants of 5,000 phantom units were made in 2002 to each non-employee director of our general partner. These units vest in 25% increments on each anniversary of June 8, 2001. The first vesting took place on June 8, 2002.

Unit Option Plan. The Unit Option Plan under our Long-Term Incentive Plan currently permits the grant of options covering common units. No grants have been made under the Unit Option Plan to date. However, the Compensation Committee may, in the future, make grants under the plan to employees and directors containing such terms as the committee shall determine, provided that unit options have an exercise price equal to the fair market value of the units on the date of grant.

Note 12 Commitments and Contingencies

We lease certain real property, equipment and operating facilities under various operating leases. We also incur costs associated with leased land, rights-of-way, permits and regulatory fees, the contracts for which generally extend beyond one year but can be cancelled at any time should they not be required for operations. Future non-cancellable commitments related to these items at December 31, 2003, are summarized below (in millions):

2004	$ 12.7
2005	$ 11.2
2006	$ 8.8
2007	$ 5.3
2008	$ 2.8
Thereafter	$ 0.7

Total lease expense incurred for 2003, 2002 and 2001 was $10.5 million, $8.3 million and $7.4 million, respectively. As is common within the industry and in the ordinary course of business, we have also entered into various operational commitments and agreements related to pipeline operations and to marketing, transportation, terminalling and storage of crude oil and LPG.

Litigation

Export License Matter. In our gathering and marketing activities, we import and export crude oil from and to Canada. Exports of crude oil are subject to the short supply controls of the Export Administration Regulations ("EAR") and must be licensed by the Bureau of Industry and Security (the "BIS") of the U.S. Department of Commerce. We have 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 have received a new license allowing for exports of volumes more than adequately reflecting our anticipated needs. On October 2, 2003, we submitted additional information to the BIS. 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 unit holders, asserts breach of fiduciary duty and breach of contract claims against the Partnership, 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. The Partnership intends to vigorously defend this lawsuit.

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