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# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION

**Washington, D. C. 20549**

# FORM 10-K/A
# AMENDMENT NO. 1

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the fiscal year ended December 31, 2003**

**OR**

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**Commission file number: 1-14569**

## PLAINS ALL AMERICAN PIPELINE, L.P.

(Exact name of registrant as specified in its charter)

**Delaware**
(State or other jurisdiction of
incorporation or organization)

**76-0582150**
(I.R.S. Employer Identification No.)

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

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

**Securities registered pursuant to Section 12(b) of the Act:**

| Title of each class | Name of each exchange on which registered |
|---|---|
| Common Units | New York Stock Exchange |

**Securities registered pursuant to Section 12(g) of the Act: None**

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

The aggregate value of the Common Units held by non-affiliates of the registrant (treating all executive officers and directors of the registrant and holders of 10% or more of the Common Units outstanding, for this purpose, as if they may be affiliates of the registrant) was approximately $1.1 billion on June 30, 2003, based on $31.48 per unit, the closing price of the Common Units as reported on the New York Stock Exchange on such date.

At February 17, 2004, there were outstanding 57,162,638 Common Units and 1,307,190 Class B Common Units.

**DOCUMENTS INCORPORATED BY REFERENCE: None**

**PLAINS ALL AMERICAN PIPELINE, L.P.**
**FORM 10-K/A—2003 ANNUAL REPORT**

**Introductory Note**

Plains All American Pipeline, L.P. is filing this Amendment No. 1 on Form 10-K/A ("Amendment No. 1") to reflect certain revisions to disclosures previously included in its Annual Report on Form 10-K for the fiscal year ended December 31, 2003, which was originally filed on March 1, 2004 (the "Original Filing"). The revisions to the Original Filing relate to a recently completed review of the Original Filing by the Securities and Exchange Commission's Division of Corporation Finance.

The following Items of the Original Filing are amended by this Amendment No. 1:

| | |
|---|---|
| Items 1 and 2. | Business and Properties |
| Item 6. | Selected Financial and Operating Data |
| Item 7. | Management's Discussion and Analysis of Financial Condition and Results of Operations |
| Item 7A. | Quantitative and Qualitative Disclosures About Market Risks |
| Item 8. | Financial Statements and Supplementary Data |
| Item 10. | Directors and Executive Officers of our General Partner |
| Item 13. | Certain Relationships and Related Transactions |
| Item 15. | Exhibits, Financial Statement Schedules and Reports on Form 8-K |

Please note that the information contained in this Form 10-K/A, including the financial statements and notes thereto, do not reflect events occurring after the date of the Original Filing, except as reflected in "Note 16—Subsequent Events (Unaudited)" in the "Notes to the Consolidated Financial Statements." For a description of these events, please read Plains All American Pipeline, L.P.'s reports filed under the Exchange Act of 1934, as amended, since March 1, 2004.

**PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES**
**FORM 10-K/A—2003 ANNUAL REPORT**

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## FORWARD-LOOKING STATEMENTS

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

- abrupt or severe production declines or production interruptions in outer continental shelf production located offshore California and transported on our pipeline system;
- 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;
- 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;
- the success of our risk management activities;
- the impact of crude oil price fluctuations;
- the availability of, and ability to consummate, acquisition or combination opportunities;
- successful integration and future performance of acquired assets;
- continued creditworthiness of, and performance by, counterparties;
- successful third-party drilling efforts in areas in which we operate pipelines or gather crude oil;
- our levels of indebtedness and our ability to receive credit on satisfactory terms;
- shortages or cost increases of power supplies, materials or labor;
- weather interference with business operations or project construction;
- the impact of current and future laws and governmental regulations;
- the currency exchange rate of the Canadian dollar;
- environmental liabilities that are not covered by an indemnity, insurance or existing reserves;
- 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 Related to Our Business" discussed in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations." Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

# PART I

## Items 1 and 2. *Business and Properties*

### General

We are a publicly traded Delaware limited partnership (the "Partnership"), formed in 1998 and engaged in interstate and intrastate crude oil transportation, and crude oil gathering, marketing, terminalling and storage, as well as the marketing and storage of liquefied petroleum gas and other petroleum products, primarily in Texas, California, Oklahoma, Louisiana and the Canadian Provinces of Alberta and Saskatchewan. Our operations can be categorized into two primary business activities:

- *Crude Oil Pipeline Transportation Operations.* We own and operate approximately 7,000 miles of gathering and mainline crude oil pipelines located throughout the United States and Canada. Our activities from pipeline operations generally consist of transporting crude oil for a fee, third party leases of pipeline capacity, barrel exchanges and buy/sell arrangements.

- *Gathering, Marketing, Terminalling and Storage Operations.* We own and operate approximately 24.0 million barrels of above-ground crude oil terminalling and storage facilities, including tankage associated with our pipeline systems. These facilities include a crude oil terminalling and storage facility at Cushing, Oklahoma. Cushing, which we refer to in this report as the Cushing Interchange, is one of the largest crude oil market hubs in the United States and the designated delivery point for NYMEX crude oil futures contracts. We utilize our storage tanks to counter-cyclically balance our gathering and marketing operations and to execute various hedging strategies to stabilize profits and reduce the negative impact of crude oil market volatility. See "—Crude Oil Volatility; Counter-Cyclical Balance; Risk Management." 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. 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 (collectively "LPG") 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; and

- 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.

To a lesser degree, we also engage in a similar business strategy with respect to the wholesale marketing and storage of LPG, which we began as a result of an acquisition in mid 2001. Since that time, the portion of our Gathering, Marketing, Terminalling and Storage Operations segment profit associated with those activities has increased from $4.2 million in 2001 to $10.0 million in 2002 and $11.6 million in 2003. The segment profit for 2001 reflects results from July 1 through December 31.

**Financial Strategy**

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 60% 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.

As of December 31, 2003, we were within our targeted credit profile. In order for us to maintain our targeted credit profile and achieve growth through acquisitions, we intend to fund acquisitions using approximately equal proportions of equity and debt. In certain cases, acquisitions will initially be financed using debt since it is difficult to predict the actual timing of accessing the market to raise equity. Accordingly, from time to time we may be temporarily outside the parameters of our targeted credit profile.

In December 2003, Moody's Investors Service raised our senior unsecured rating to Ba1, affirmed our senior implied credit rating of Ba1 and placed us on review for a possible ratings upgrade. In November 2003, Standard & Poor's raised our senior unsecured rating to BBB- (the same rating as our senior implied rating) from BB+. 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.

**Competitive Strengths**

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

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

- ***Our Cushing Terminal is strategically located, operationally flexible and readily expandable.*** Our Cushing Terminal interconnects with the Cushing Interchange's major inbound and outbound pipelines, providing access to both foreign and domestic crude oil. Our Cushing Terminal is the most modern large-scale terminalling and storage facility at the Cushing Interchange, incorporating (i) operational enhancements designed to safely and efficiently terminal, store, blend and segregate large volumes and multiple varieties of crude oil and (ii) extensive environmental safeguards. Since completing the initial construction of the Cushing Terminal in 1994, we have completed three expansion phases of approximately 1.1 million barrels each, thus expanding the facility to its current capacity of 5.3 million barrels. In January 2004, we announced the commencement of our Phase IV expansion project, which will increase capacity by an incremental 1.1 million barrels, or approximately 20% of current capacity. We believe that the facility can be further expanded to meet additional demand should market conditions warrant. In addition, we own approximately 18.7 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.

- ***The combination of our business activities provide a counter-cyclical balance.*** We believe the manner in which we integrate the activities of our gathering and marketing operations with our terminalling and storage operations provides a counter-cyclical balance to our business, irrespective of the structure of the crude oil market. In combination with our pipeline transportation operations, we believe these activities have 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, borrow under our credit facilities and issue additional notes in the long-term debt capital markets. We have committed senior unsecured facilities totaling $750 million. Under our committed facilities, each bank has committed to lend to us its pro rata share of the total facility amount. These credit facilities are available for working capital purposes and to fund capital expenditures, including acquisitions. At December 31, 2003, we had approximately $596.8 million of unused capacity under these credit facilities. We also have a $200 million uncommitted facility to finance the purchase of hedged crude oil inventory. Under our uncommitted facility, the banks have made no binding commitment to lend; rather, the banks can exercise discretion with respect to each borrowing request. Once they have agreed to lend, however, the amounts associated with any particular borrowing becomes "committed" in that the banks have no discretion to demand prepayment. The uncommitted facility is secured by the purchased inventory and related receivables. At December 31, 2003, we have approximately $100 million outstanding under our hedged crude oil inventory facility resulting in unused uncommitted capacity of approximately $100 million under this facility. Our usage is subject to covenant compliance. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

- ***We have an experienced management team whose interests are aligned with those of our stakeholders.*** 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, approximately 400,000 common units and, through phantom unit grants and options, own contingent equity incentives that vest primarily upon achievement of specified performance objectives. A significant portion of the awards under our Long-Term Incentive Plan ("LTIP") have vested or will vest in the first half of 2004.

**Organizational History**

We were formed in September 1998 to acquire and operate the midstream crude oil business and assets of Plains Resources Inc. and its wholly-owned subsidiaries ("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 the limited partner units held by Plains Resources, Plains Resources' overall effective ownership in us was reduced to approximately 22% as of February 17, 2004. See Item 12. "Security Ownership of Certain Beneficial Owners and Management and Related Unitholders' Matters."

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

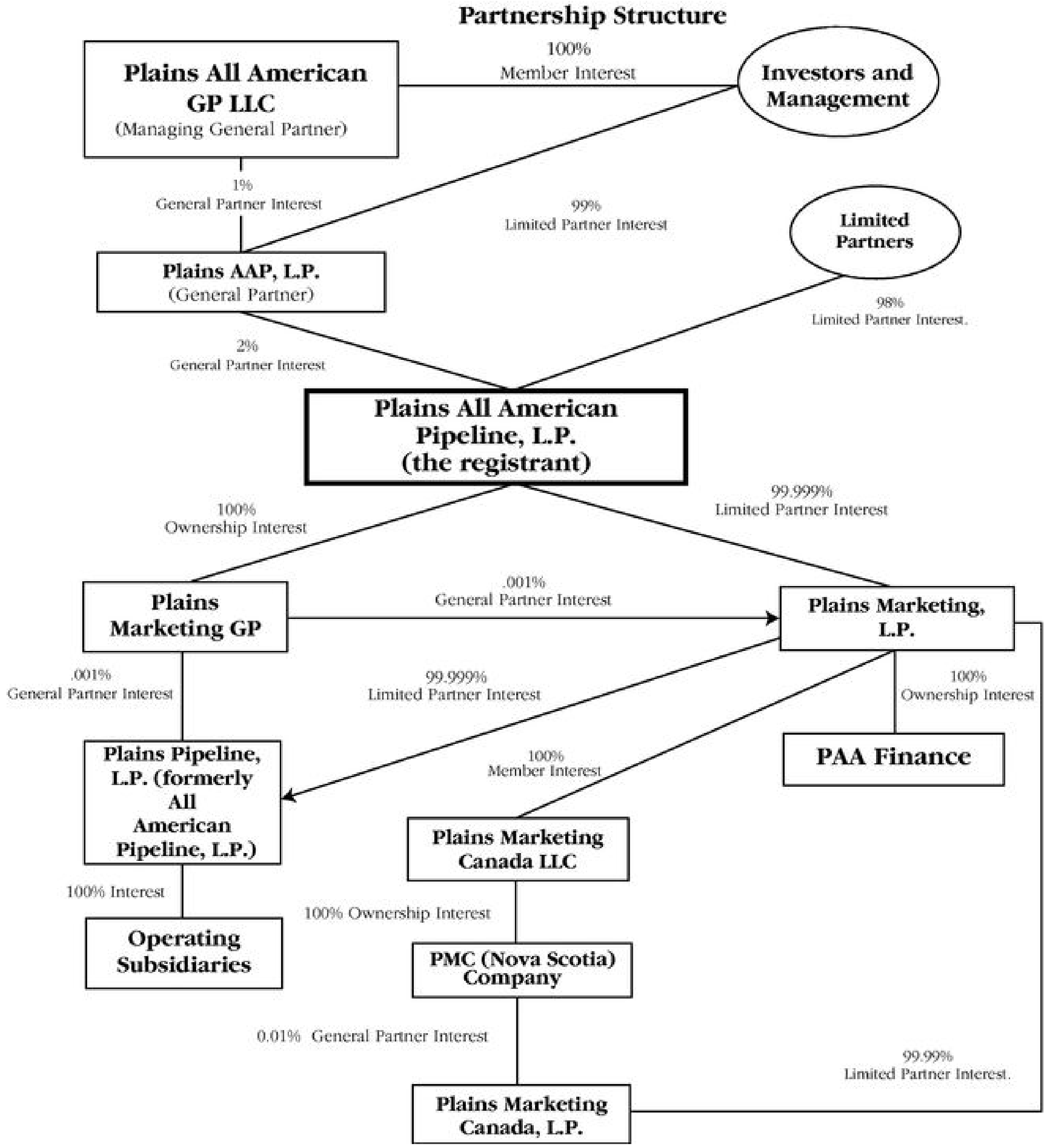
**Partnership Structure and Management**

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. We currently have fewer than 20 subsidiaries, although we may form new subsidiaries from time to time in connection with acquisitions.

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. Our general partner does not receive a management fee or other compensation in connection with its management of our business, but it is reimbursed for all direct and indirect expenses incurred on our behalf. Canadian personnel are employed by Plains Marketing Canada L.P.'s general partner, PMC (Nova Scotia) Company.

Our general partner owns all of the incentive distribution rights. These rights provide that our general partner receives an increasing percentage of cash distributions (in addition to its 2% general partner interest) as distributions reach and exceed certain threshold levels. See Item 5. "Market for the Registrant's Common Units and Related Unitholder Matters—Cash Distribution Policy."

The chart below depicts the current organization and ownership of the Partnership, the operating partnerships and the 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. 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 $1.3 billion. In addition, from time to time we have sold assets that are no longer considered essential to our operations.

During 2003, we completed ten acquisitions for aggregate consideration of approximately $159.5 million. In addition, in December 2003, we signed a definitive agreement with Shell Pipeline Company to acquire entities owning pipeline and terminal assets for $158 million. Following is a brief description of this pending acquisition, acquisitions completed in 2003 that exceeded $15 million and major acquisitions and dispositions that have occurred since our initial public offering in November 1998.

***Pending Acquisition of Capline and Capwood Pipeline System***

On December 16, 2003, we entered into a definitive agreement to acquire all of Shell Pipeline Company LP's ("SPLC") interests in two entities. 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 667-mile, 40-inch mainline crude oil pipeline originating in St. James, Louisiana, and terminating in Patoka, Illinois. The Capline system is operated by Shell Pipeline Company, LP and 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 being acquired. During 2003, throughput on the interest in the Capline System we are acquiring 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 we are acquiring. 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. After closing, we anticipate that we will assume the operatorship of the Capwood system from SPLC. During 2003, throughput on the interest being acquired averaged approximately 107,000 barrels per day.

This acquisition is expected to close during the first quarter of 2004. While we believe it is reasonable to expect the acquisition to close in the first quarter of 2004, we can provide no assurance as to when or whether the acquisition will close.

***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. 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, the Partnership 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, 95-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 2002, the Iraan to Midland Pipeline System transported approximately 21,000 barrels per day of crude oil. 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 a package 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 2 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 315 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 347-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 8.9 million barrels (net to our interest) of above-ground crude oil terminalling and storage assets in West Texas from Shell Pipeline Company LP and Equilon Enterprises LLC (the "Shell acquisition"). The primary assets included in the transaction are interests in the Basin Pipeline System ("Basin System"), the Permian Basin Gathering System ("Permian Basin System") and the Rancho Pipeline System ("Rancho System"). The total purchase price of $324.4 million consisted of (i) $304.0 million in cash, which was borrowed under our revolving credit facility, (ii) approximately $9.1 million related to the settlement of pre-existing accounts receivable and inventory balances and (iii) approximately $11.3 million of estimated transaction and closing costs.

The acquired assets are primarily fee-based mainline crude oil pipeline transportation assets that gather crude oil in the Permian Basin and transport that crude oil to major market locations in the Mid-Continent and Gulf Coast regions. The acquired assets complement our existing asset infrastructure in West Texas and represent a transportation link to Cushing, Oklahoma, where we provide storage and terminalling services. In addition, we believe that the Basin system is poised to benefit from potential shut-downs of refineries and other pipelines due to the shifting market dynamics in the West Texas area. As was contemplated at the time of the acquisition, the Rancho system was taken out of service in March 2003, pursuant to the terms of its operating agreement. See "—Shutdown and Partial Sale of Rancho Pipeline System."

***Canadian Expansion***

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

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

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

***West Texas Gathering System***

In July 1999, we completed the acquisition of the West Texas Gathering System from Chevron Pipe Line Company for approximately $36.0 million, including transaction costs. The assets acquired include approximately 420 miles of crude oil mainlines, approximately 295 miles of associated gathering and lateral lines, and approximately 2.9 million barrels of tankage located along the system.

***Scurlock Permian***

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

Scurlock, previously a wholly owned subsidiary of Marathon Ashland Petroleum, was engaged in crude oil transportation, gathering and marketing. The assets acquired included approximately 2,300 miles of active pipelines, numerous storage terminals and a fleet of trucks. The largest asset consists of an approximately 920-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 midstream crude oil assets. 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.

We are currently involved in advanced discussions with a potential seller regarding the purchase by us of crude oil pipeline, terminalling, storage and gathering and marketing assets for an aggregate purchase price, including assumed liabilities and obligations, ranging from $300 million to $400 million. Such transaction is subject to confirmatory due diligence, negotiation of a mutually acceptable definitive purchase and sale agreement, regulatory approval and approval of both our board of directors and that of the seller.

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 $0.4 million in deferred costs at December 31, 2003. We estimate that our deferred acquisition costs will increase in the first quarter of 2004 by approximately $0.7 million. 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 Partial Sale 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.

***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 five provinces in Canada. The majority of our operations are conducted in Texas, Oklahoma, California, 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**

We own and operate approximately 7,000 miles of gathering and mainline crude oil pipelines located throughout the United States and Canada. Our activities from pipeline operations generally consist of transporting crude oil for a fee, third party leases of pipeline capacity, barrel exchanges and buy/sell arrangements.

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

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

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

***Southwest U.S.***

*Basin Pipeline System.* We acquired an approximate 87% undivided joint interest in the Basin System in the Shell acquisition. The Basin System is a 514-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 263,000 barrels per day (net to our interest) during 2003. 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 February 2004, we announced plans to expand a 345-mile section of the system. The section to be expanded extends from Colorado City, Texas to our Cushing Terminal. Upon the completion of this estimated $1.1 million expansion, the capacity of this section will increase 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 87,000 barrels per day in 2003. 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 2.9 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 927 miles of pipe and primarily transports crude oil from wells in the Permian Basin to the Basin System. The Permian Basin System gathered approximately 48,000 barrels per day in 2003. The Permian Basin System includes approximately 3.2 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 920 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 year ended December 31, 2003, the Spraberry Pipeline System gathered approximately 38,000 barrels per day of crude oil. The Spraberry Pipeline System also includes approximately 364,000 barrels of tank capacity located along the pipeline.

*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 2003, 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 and in Midland.

*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, 95-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 last six months of 2003, deliveries averaged approximately 30,000 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 315 miles of active crude oil gathering lines. During the last ten months of 2003, volumes on this system averaged 23,000 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. See "—Acquisitions and Dispositions—All American Pipeline Linefill Sale and Asset Disposition." 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 130 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 Plains Exploration and Production Company ("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 Item 13. "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 segment profit is derived from pipeline transportation margins associated with these two fields. For the year ended December 31, 2003, approximately $29 million, or 13%, of our aggregate revenues less direct field operating costs was attributable to the Santa Ynez field and approximately $8 million, or 4% was attributable to the Point Arguello field.

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 the Partnership has grown and diversified through acquisitions and organic expansions and as a result of declines in volumes produced and transported from these fields, offset somewhat by an increase in pipeline tariffs. Over the last several years, transportation volumes received from the Santa Ynez and Point Arguello fields have declined from 92,000 and 60,000 average daily barrels, respectively, in 1995 to 46,000 and 13,000 average daily barrels, respectively, for the year ended December 31, 2003. We expect that there will continue to be natural production declines from each of these fields as the underlying reservoirs are depleted. A 5,000 barrel per day decline in volumes shipped from these fields would result in a decrease in annual pipeline tariff revenues of approximately $3.3 million, based on a tariff of $1.81 per barrel.

In October 2003, PXP announced that it had received all of the necessary permits to develop a portion of the Rocky Point structure that is accessible from the Point Arguello platforms and it appears that they will commence drilling activities in the second quarter of 2004. Such drilling activities, if successful, 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.

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2003 | 2002 | 2001 | 2000 | 1999 |
| | (barrels in thousands) | | | | |
| Average daily volumes received from: | | | | | |
| Port Arguello (at Gaviota) | 13 | 16 | 18 | 18 | 20 |
| Santa Ynez (at Las Flores) | 46 | 50 | 51 | 56 | 59 |
| Total | 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 600,000 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.

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2003 | 2002 | 2001 | 2000 | 1999 |
| | (barrels in thousands) | | | | |
| Total average daily volumes | 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 373-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 2003 were approximately 71,000 barrels of crude oil per day (approximately 16,000 barrels per day, net to our 22% interest). The operator of the system is Bridger Pipeline.

***U.S. Gulf Coast***

*Sabine Pass Pipeline System.* The Sabine Pass Pipeline System, acquired in the Scurlock acquisition, is a common carrier crude oil pipeline system. The Sabine Pass Pipeline System primarily gathers crude oil from onshore facilities of offshore production near Johnson's Bayou, Louisiana, and delivers it to tankage and barge loading facilities in Sabine Pass, Texas. The Sabine Pass Pipeline System consists of approximately 35 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. In 2003, the system transported approximately 15,000 barrels of crude oil per day. The Sabine Pass Pipeline System also includes 245,000 barrels of tank capacity located along the pipeline.

*Ferriday Pipeline System.* The Ferriday Pipeline System, acquired in the Scurlock acquisition, is a common carrier crude oil pipeline system located in eastern Louisiana and western Mississippi. The Ferriday Pipeline System consists of approximately 570 miles of pipe ranging from 2 inches to 12 inches in diameter. In 2003, the Ferriday Pipeline System delivered approximately 7,000 barrels of crude oil per day to third party pipelines that supplied refiners in the Midwest. The Ferriday Pipeline System also includes approximately 332,000 barrels of tank capacity located along the pipeline.

*La Gloria Pipeline System.* The La Gloria Pipeline System, acquired in the Scurlock acquisition, is a proprietary crude oil pipeline system that in 2003 transported approximately 24,000 barrels of crude oil per day to Crown Central's refinery in Longview, Texas. Crown Central's deliveries are subject to a throughput and deficiency agreement, which extends through 2004.

*Red River Pipeline System.* The Red River Pipeline System, acquired in 2003, is a 347-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 2003, the system transported approximately 8,000 barrels of crude oil per day. The system also includes approximately 645,000 barrels of crude oil storage capacity. In 2003, we completed a connection of the pipeline system to our Cushing Terminal.

*ArkLaTex Pipeline System.* The ArkLaTex Pipeline System, acquired from Link Energy (formerly EOTT Energy) in September 2003, consists of 240 miles of active crude oil gathering and mainline pipelines and connects to our Red River Pipeline System near Sabine, Texas. Also included in the transaction were 470,000 barrels of active crude oil storage capacity. During the fourth quarter of 2003, volumes transported averaged 13,000 barrels per day.

*Atchafalaya Pipeline System.* The Atchafalaya Pipeline System, which we own 100% through three separate transactions in 2003, originates near Garden City, Louisiana and traverses east to its terminus near Gibson, Louisiana. The system consists of 28 miles of active 8-inch crude oil and condensate pipelines. In the last half of 2003, the system transported approximately 12,000 barrels per day of crude oil and condensate.

*Eugene Island Flowline System.* We own from 38%-56% (depending upon the segment and throughput level) of the Eugene Island Flowline System ("EIFS"). 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 last half of 2003 were approximately 16,000 barrels per day (8,200 barrels per day, net to our interest) of crude oil.

***Central U.S.***

*Illinois Basin Pipeline System.* The Illinois Basin Pipeline System, acquired with the Scurlock acquisition, consists of common carrier pipeline and gathering systems and truck injection facilities in southern Illinois. The Illinois Basin Pipeline System consists of approximately 80 miles of pipe of varying diameter and in 2003 delivered approximately 2,900 barrels of crude oil per day to third party pipelines that supply refiners in the Midwest. For the year ended December 31, 2003, approximately 2,500 barrels of crude oil per day of the supply on this system came from fields operated by PXP.

***Canada***

*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 68,000 barrels of crude oil and condensate per day in 2003.

*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 in 2003.

*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. In 2003, the North Saskatchewan Pipeline System delivered approximately 6,000 barrels of crude oil and condensate per day into the Manito Pipeline. Our ownership interest in the North Saskatchewan Pipeline System is approximately 36%.

*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. In 2003, the Cactus Lake/Bodo Pipeline System transported approximately 26,000 barrels per day (approximately 3,000 barrels per day, net to our interest) of crude oil and condensate. Our ownership interest in the Cactus Lake segment is 13.125% and our ownership interest in the Bodo Pipeline is 76.25%. We also own various interests in the lateral lines in these systems.

*Wascana Pipeline System.* The Wascana Pipeline System, acquired in the Murphy acquisition, is an NEB-regulated system located in Saskatchewan, Canada. The Wascana Pipeline System is a 107-mile crude oil pipeline that connects to the Bridger Pipeline system at the United States border near Raymond, Montana. In 2003, the Wascana Pipeline System transported approximately 9,000 barrels of crude oil per day.

*Wapella Pipeline System.* The Wapella Pipeline System is a 79 mile, NEB-regulated system located in southeastern Saskatchewan and southwestern Manitoba. In 2003, the Wapella Pipeline System delivered approximately 10,000 barrels of crude oil per day to the Enbridge Pipeline at Cromer, Manitoba. The system also includes approximately 18,500 barrels of crude oil storage capacity.

*South Saskatchewan Pipeline System.* The South Saskatchewan Pipeline System, which was acquired in November 2003, originates approximately 75 miles southwest of Swift Current, Saskatchewan, and traverses north and east until it reaches its terminus at Regina. The system consists of a 158-mile, 16-inch mainline and 203 miles of gathering lines ranging in diameter from three to twelve inches. During the period of 2003 that we owned the system, it transported approximately 52,000 barrels of crude oil per day. At Regina, the system can deliver crude oil to the Enbridge Pipeline System and to local markets. In addition, the system can indirectly deliver crude oil into our Wascana Pipeline System.

**Gathering, Marketing, Terminalling and Storage Operations**

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

*Gathering and Marketing Operations*

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

- purchasing crude oil from producers at the wellhead and in bulk from aggregators at major pipeline interconnects and trading locations;
- 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:

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2003 | 2002 | 2001 | 2000 | 1999 |
| | (barrels in thousands) | | | | |
| Lease gathering | 437 | 410 | 348 | 262 | 265 |
| Bulk purchases(1) | 90 | 68 | 46 | 28 | 138 |
| Total volumes | 527 | 478 | 394 | 290 | 403 |

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

*Crude Oil Purchases.* We purchase crude oil from producers under contracts, the majority of which range in term from a thirty-day evergreen to three years. In a typical producer's operation, crude oil flows from the wellhead to a separator where the petroleum gases are removed. After separation, the crude oil is treated to remove water, sand and other contaminants and is then moved into the producer's on-site storage tanks. When the tank is full, the producer contacts our field personnel to purchase and transport the crude oil to market. We utilize our truck fleet and gathering pipelines as well as third party pipelines, trucks and barges to transport the crude oil to market. We own or lease approximately 300 trucks used for gathering crude oil.

Since 1998, we have had a marketing arrangement with Plains Resources, under which we have been the exclusive marketer and purchaser for all of Plains Resources' equity crude oil production (including its subsidiaries that conduct exploration and production activities). In connection with the separation of Plains Resources and one of its subsidiaries discussed below, Plains Resources divested the bulk of its producing properties. As a result, we do not anticipate the marketing arrangement with Plains Resources to be material to our operating results in the future.

In December 2002, Plains Resources completed a spin-off to its stockholders of PXP. We currently have a marketing agreement with PXP for the majority of its equity crude oil production and that of its subsidiaries. The marketing agreement provides that we will purchase PXP's equity crude oil production for resale at market prices, for which we charge a fee of $0.20 per barrel. This fee will be adjusted every three years based upon then existing market conditions. We are currently negotiating an amendment to the terms of the marketing agreement with PXP. See Item 13. "Certain Relationships and Related Transactions—Transactions with Related Parties—General."

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

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

We establish a margin for crude oil we purchase by selling crude oil for physical delivery to third party users, such as independent refiners or major oil companies, or by entering into a future delivery obligation with respect to futures contracts on the NYMEX and over-the-counter. Through these transactions, we seek to maintain a position that is substantially balanced between crude oil purchases and sales and future delivery obligations. From time to time, we enter into various types of sale and exchange transactions including fixed price delivery contracts, floating price collar arrangements, financial swaps and crude oil futures contracts as hedging devices. Except for pre-defined inventory positions, our policy is generally to purchase only crude oil for which we have a market, to structure our sales contracts so that crude oil price fluctuations do not materially affect the segment profit we receive, and to not acquire and hold crude oil, futures contracts or other derivative products for the purpose of speculating on crude oil price changes that might expose us to indeterminable losses. See "Crude Oil Volatility; Counter-Cyclical Balance; Risk Management." In November 1999, we discovered that this policy was violated, and we incurred $174.0 million in unauthorized trading losses, including associated costs and legal expenses. In 2000, we recognized an additional $7.0 million charge related to the settlement of litigation for an amount in excess of established reserves.

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

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

*Liquefied Petroleum Gas and Other Petroleum Products.* We also market and store LPG and other petroleum products throughout the United States and Canada, concentrated primarily in Washington, California, Kansas, Michigan, Texas, Montana, Nebraska and the Canadian provinces of Alberta and Ontario. These activities include:

- purchasing LPG (primarily propane and butane) from producers at gas plants and in bulk at major pipeline terminal points and storage locations;
- transporting the LPG via common carrier pipelines, railcars and trucks to our own terminals and third party facilities for subsequent resale by them to retailers and other wholesale customers; and
- exchanging product to other locations to maximize margins and/or to meet contract delivery requirements.

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

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

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

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

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

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

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

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

When we market crude oil, we must determine the amount, if any, of the line of credit to be extended to any given customer. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures. If we determine that a customer should receive a credit line, we must then decide on the amount of credit that should be extended. Because our typical sales transactions can involve tens of thousands of barrels of crude oil, the risk of nonpayment and nonperformance by customers is a major consideration in our business. We believe our sales are made to creditworthy entities or entities with adequate credit support. Generally, sales of crude oil are settled within 30 days of the month of delivery, and pipeline, transportation and terminalling services also settle within 30 days from invoice for the provision of services.

We also have credit risk with respect to our sales of LPG; however, because our sales are typically in relatively small amounts to individual customers, we do not believe that we have material concentration of credit risk. Typically, we enter into annual contracts to sell LPG on a forward basis, as well as sell LPG on a current basis to local distributors and retailers. In certain cases our customers prepay for their purchases, in amounts ranging from $0.05 per gallon to 100% of their contracted amounts. Generally, sales of LPG are settled within 30 days of the date of invoice.

***Terminalling and Storage Operations***

We own approximately 24.0 million barrels of terminalling and storage assets, including tankage associated with our pipeline and gathering systems. Our storage and terminalling operations increase our margins in our business of purchasing and selling crude oil and also generate revenue through a combination of storage and throughput charges to third parties. Storage fees are generated when we lease tank capacity to third parties. Terminalling fees, also referred to as throughput fees, are generated 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). See "—Crude Oil Volatility; Counter-Cyclical Balance; Risk Management."

Our most significant terminalling and storage asset is our Cushing Terminal located at the Cushing Interchange. The Cushing Interchange is one of the largest wet-barrel trading hubs in the U.S. and the delivery point for crude oil futures contracts traded on the NYMEX. The Cushing Terminal has been designated by the NYMEX as an approved delivery location for crude oil delivered under the NYMEX light sweet crude oil futures contract. As the NYMEX delivery point and a cash market hub, the Cushing Interchange serves as a primary source of refinery feedstock for the Midwest refiners and plays an integral role in establishing and maintaining markets for many varieties of foreign and domestic crude oil. Our Cushing Terminal was constructed in 1993 to capitalize on the crude oil supply and demand imbalance in the Midwest. The Cushing Terminal is also used to support and enhance the margins associated with our merchant activities relating to our lease gathering and bulk purchasing activities. See "—Gathering and Marketing Operations—Bulk Purchases." In 1999, we completed our 1.1 million barrel Phase I expansion project, which increased the facility's total storage capacity to 3.1 million barrels. On July 1, 2002, we placed in service approximately 1.1 million barrels of tank capacity associated with our Phase II expansion of the Cushing Terminal, raising the facility's total storage capacity to approximately 4.2 million barrels. In January 2003, we placed in service our 1.1 million barrel Phase III expansion. The expansion increased the capacity of the Cushing Terminal to a total of approximately 5.3 million barrels. The Cushing Terminal now consists of fourteen 100,000-barrel tanks, four 150,000-barrel tanks and twelve 270,000-barrel tanks, all of which are used to store and terminal crude oil. In January 2004, we announced the commencement of our Phase IV expansion project, which will increase capacity by an incremental 1.1 million barrels, or approximately 20%. 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 30 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 5.7 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. 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 an audible and visual 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.

The following table sets forth throughput volumes for our terminalling and storage operations and quantity of tankage leased to third parties for our Cushing Terminal for the past five years.

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2003 | 2002 | 2001 | 2000 | 1999 |
| | (barrels in thousands) | | | | |
| Throughput volumes (average daily volumes) | 208 | 110 | 94 | 59 | 72 |
| Storage leased to third parties (average monthly volumes)(1) | 1,165 | 1,067 | 2,136 | 1,437 | 1,743 |

(1) The level of tankage at Cushing that we allocate for our arbitrage activities (and therefore is not available for lease to third parties) varies throughout crude oil price cycles.

We also own an LPG storage facility located in Alto, Michigan, which 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 38 million gallons of LPG. We believe the facility will further support the expansion of our LPG business in Canada and the northern tier of the U.S. as we combine the facility's existing fee-based storage business with our wholesale propane marketing expertise. In addition, there may be opportunities to expand this facility 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 as high as $40.00 per barrel 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 and an aggregate of 250,000 barrels of LPG. 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 than in the past. This accounting treatment is discussed further in Note 2 "Summary of Significant Accounting Policies" in the "Notes to the Consolidated Financial Statements."

**Geographic Data; Financial Information about Segments**

See Note 15 "Operating Segments" in the "Notes to the Consolidated Financial Statements."

### Customers

See Note 9 "Major Customers and Concentration of Credit Risk" in the "Notes to the Consolidated Financial Statements."

### 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 Canada and in some states in which we conduct intrastate common carrier or private pipeline operations.

Pipeline safety issues are currently receiving significant attention in various political and administrative arenas at both the state and federal levels. For example, recent federal rule changes require pipeline operators to: (1) develop and maintain a written qualification program for individuals performing covered tasks on pipeline facilities, and (2) establish pipeline integrity management programs. In particular, during 2000, the DOT adopted new regulations requiring operators of interstate pipelines 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 are located in high consequence areas. The DOT rule requires 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, including enhanced damage prevention programs, corrosion control program improvements, leak detection system enhancements, installation of emergency flow restricting devices, and emergency preparedness improvements. The DOT rule also requires 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 carryout this program will be approximately $1.8 million in 2004. The relative increase in program cost for 2004 is primarily attributable to pipeline segments acquired in 2003, that are subject to the new regulation and which were scheduled for assessment in 2004. These costs are recurring in nature and thus will also impact future periods. 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 regulations imposed in the future. We will continue to refine our estimates as information from initial assessments is collected.

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.

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 63% of our 24.0 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 an approximate average of $3 million per year through 2009 (approximately $2 million in 2004) in connection with API 653 compliance activities. Such amounts incorporate the costs associated with the assets acquired in 2003. We will continue to refine our estimates as information from initial assessments is collected.

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 these standards. The timing of such additional costs is uncertain and could vary materially from our current projections.

Since the terrorist attacks of September 11, 2001, 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 (an agency of the Department of Homeland Security, which has assumed responsibility from the DOT). 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. See "—Operational Hazards and Insurance."

***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 crude oil, as well as refined product and petrochemical 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 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, 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. 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 Energy Policy Act deemed petroleum pipeline rates in effect for the 365-day period ending on the date of enactment of the Energy Policy Act or that were in effect on the 365th day preceding enactment and had not been subject to complaint, protest or investigation during the 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 either that a substantial change in the economic circumstances of the oil pipeline that were a basis for the rate or in the nature of the services has occurred since enactment or that a provision of the tariff is unduly discriminatory or preferential.

In a proceeding involving Lakehead Pipe Line Company, Limited Partnership (Opinion Nos. 397 and 397-A), the FERC concluded that there should not be a corporate income tax allowance built into a petroleum pipeline's rates to reflect income attributable to noncorporate partners because noncorporate partners, unlike corporate partners, do not pay a corporate income tax. Additionally, on January 13, 1999, the FERC issued Opinion No. 435 in a proceeding involving SFPP, L.P., which, among other things, affirmed Opinion No. 397's determination that there should not be a corporate income tax allowance built into a petroleum pipeline's rates to reflect income attributable to noncorporate partners. Petitions for review of Opinion No. 435 and subsequent FERC opinions in that case are pending before the D.C. Circuit Court of Appeals.

In another FERC proceeding involving SFPP, L.P., certain shippers are challenging grandfathered rates on the basis of changed circumstances since the passage of the Energy Policy Act. The ultimate disposition of this challenge may define "substantial change" in such a way as to make grandfathered rates more vulnerable to challenge than has historically been the case. We are uncertain what effect, if any, an unfavorable determination in the FERC proceeding might have on our grandfathered tariffs.

*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 of the parties.

***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 provincial 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 and local tax requirements could lead to the imposition of additional taxes, interest and penalties. See Item 3. "Legal Proceedings."

**Environmental, Health and Safety Regulation**

***General***

Numerous federal, state and local laws and regulations governing the discharge of materials into the environment, or otherwise relating to the protection of the environment, affect our operations and costs. In particular, our activities in connection with storage and transportation of crude oil and other liquid hydrocarbons and our use of facilities for treating, processing or otherwise handling hydrocarbons and wastes are subject to stringent environmental laws and regulations. As with the industry generally, compliance with existing and anticipated laws and regulations increases our overall cost of business, including our capital costs to construct, maintain and upgrade equipment and facilities. Although these regulations affect our capital expenditures and earnings, we believe that they do not affect our competitive position because our competitors that comply with such laws and regulations are similarly affected. Environmental laws and regulations have historically been subject to change, and we are unable to predict the ongoing cost to us of complying with these laws and regulations or the future impact of such laws and regulations on our operations. Violation of environmental laws and regulations and any associated permits can result in the imposition of significant administrative, civil and criminal penalties, injunctions and construction bans or delays. A discharge of petroleum hydrocarbons or hazardous substances 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 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 ("FWPCA"), and other statutes as they pertain to prevention and response to oil spills. The OPA subjects 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 or resulted from a violation of a federal safety, construction, or operating regulation. If a party fails to report a spill or cooperate in the cleanup, the liability limits likewise do not apply. In the event of an oil spill into navigable waters, substantial liabilities could be imposed upon us. States in which we operate have also enacted similar laws. Regulations have been or are currently being developed under OPA and state laws that may also impose additional regulatory burdens on our operations. We believe that we are in substantial compliance with applicable OPA requirements.

The FWPCA imposes restrictions and strict controls regarding the discharge of pollutants into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters. The FWPCA imposes substantial potential liability for the costs of removal, remediation and damages. 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 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 these state requirements.

***Air Emissions***

Our operations are subject to the Federal Clean Air Act, as amended, and comparable state, local and provincial statutes. We believe that our operations are in substantial compliance with these statutes in all 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 recent or soon to be adopted changes to state implementation plans for controlling air emissions in regional non-attainment areas require or will 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 will 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 give no assurances, we believe on-going compliance with the 1990

Federal Clean Air Act Amendments will not have a material adverse effect on our financial condition or results of 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 statutes. The EPA is considering the adoption of stricter disposal standards for non-hazardous wastes, including oil and gas wastes. We are not currently required to comply with a substantial portion of the RCRA requirements because our operations generate minimal quantities of hazardous wastes. However, it is possible that additional wastes, which could include wastes generated by our operations that are currently classified as non-hazardous wastes, will in the future be designated as "hazardous wastes." Hazardous wastes are subject to more rigorous and costly disposal requirements than are non-hazardous wastes. Such changes in the regulations could result in additional capital expenditures or operating expenses for us as well as the industry in general.

***Hazardous Substances***

The Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), also known as "Superfund," and comparable state 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 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. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible classes of persons. 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." We may be 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 disposed of or released into the environment.

We currently own or lease, and have in the past owned or leased, properties where hydrocarbons are being or have been handled. Although we have utilized operating and disposal practices that were standard in the industry at the time, waste hydrocarbons or other 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 hydrocarbons or other wastes was not under our control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed 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. See "—Environmental Remediation."

***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.

***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.

***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***

In connection with our 1999 acquisition of Scurlock Permian LLC from Marathon Ashland Petroleum, or "MAP," we were indemnified by MAP for any environmental liabilities attributable to Scurlock's business or properties which occurred prior to the date of the closing of the acquisition. This indemnity applied to claims associated with sites that were not listed in the acquisition agreement and which exceeded $25,000 individually and $1.0 million in the aggregate. For the indemnity to apply, we were required to assert any claims as to unlisted sites on or before May 15, 2003. In conjunction with the expiration of this indemnity, we reached a settlement agreement with respect to MAP's remaining indemnity obligations. Under the terms of this agreement, MAP will continue to remain obligated for liabilities associated with the sites listed in the acquisition agreement, including two Superfund sites at which it is alleged that Scurlock Permian deposited waste oils. In addition, MAP paid us $4.6 million cash as satisfaction of its obligations with respect to unlisted sites.

In connection with our acquisition of Murphy Oil Company Ltd.'s midstream operations in Canada, we identified a limited number of environmental deficiencies during due diligence. Under the terms of our acquisition agreement, Murphy, at its sole cost and expense, agreed to remediate (to the minimum standards required by applicable environmental law) the identified environmental deficiencies. For environmental deficiencies that were not identified at the time of acquisition, but which occurred prior to closing, and were identified to Murphy prior to January 31, 2002, we have agreed to be responsible up to an aggregate amount of $300,000. Thereafter, Murphy Oil Company Ltd., agreed to remain solely responsible for the costs to remediate that exceed $20,000 for each environmental deficiency for a total of not more than ten environmental deficiencies as chosen by us. Except for the environmental deficiencies identified at the time of acquisition, Murphy's maximum liability for environmental deficiencies identified post-acquisition cannot exceed $2.25 million. We have identified potential remediation costs for these assets, and have included such costs in the total environmental reserve described below.

In connection with our acquisition of the West Texas Gathering System, we agreed to be responsible for pre-acquisition environmental liabilities up to an aggregate amount of $1.0 million, while Chevron Pipe Line Company agreed to remain solely responsible for liabilities discovered prior to July 2002 that exceed this $1.0 million threshold. Based on investigations of these assets, we have identified several sites that exceed or will exceed the threshold limitations for the indemnity, and we have notified Chevron of their responsibility to indemnify us for these costs. Our portion of the potential remediation costs have been included in the total environmental reserve described below.

In connection with the Shell Acquisition 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 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. 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. To the extent our assessment involves projected costs that are neither indemnified nor insured, we include such costs in our environmental reserve.

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 an extensive inspection program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to any future environmental releases from our assets may substantially affect our business.

Our total environmental reserve, which includes our estimated remediation costs for all of the assets described above, approximated $6.6 million at December 31, 2003. We believe this environmental reserve is adequate, and in conjunction with our indemnification arrangements described above should prevent remediation costs from having a material adverse effect on our financial condition, results of operations or cash flows. However, no assurance can be given that any costs incurred in excess of this reserve or outside of the indemnifications would not have a material adverse effect on our financial condition, results of operations or cash flows.

**Operational Hazards and Insurance**

Pipelines, terminals or other facilities 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 the Partnership and its 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 approximately 250% 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. 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.

This overall trend of contraction in the breadth and depth of available coverage and increases in costs, deductibles and retention levels was reinforced in connection with the renewal of our insurance program in June 2003. Absent a material favorable change in available insurance markets, this trend of rising insurance-related costs is expected to continue as we continue to grow and expand. As a result, it is anticipated that we will elect to self-insure more activities against certain of these operating hazards.

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. 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 or indemnified against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe that we are adequately insured for public liability and property damage to others with respect to our operations. With respect to all of our coverage, no assurance can be given that we will be able to maintain adequate insurance in the future at rates we consider reasonable.

**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 1,300 employees at December 31, 2003. None of the employees of our general partner were represented by labor unions, and our general partner considers its employee relations to be good.

**Summary of Tax Considerations**

The tax consequences of ownership of common units depends in part on the owner's individual tax circumstances. However, the following is a brief summary of material tax consequences of owning and disposing of common units.

***Partnership Status; Cash Distributions***

We are classified for federal income tax purposes as a partnership based upon our meeting certain requirements imposed by the Internal Revenue Code (the "Code"), which we must meet each year. The owners of common units are considered partners in the Partnership so long as they do not loan their common units to others to cover short sales or otherwise dispose of those units. Accordingly, we pay no federal income taxes, and a common unitholder is required to report on the unitholder's federal income tax return the unitholder's share of our income, gains, losses and deductions. In general, cash distributions to a common unitholder are taxable only if, and to the extent that, they exceed the tax basis in the common units held.

***Partnership Allocations***

In general, our income and loss is allocated to the general partner and the unitholders for each taxable year in accordance with their respective percentage interests in the Partnership (including, with respect to the general partner, its incentive distribution right), as determined annually and prorated on a monthly basis and subsequently apportioned among the general partner and the unitholders of record as of the opening of the first business day of the month to which they relate, even though unitholders may dispose of their units during the month in question. A unitholder is required to take into account, in determining federal income tax liability, the unitholder's share of income generated by us for each taxable year of the Partnership ending within or with the unitholder's taxable year, even if cash distributions are not made to the unitholder. As a consequence, a unitholder's share of our taxable income (and possibly the income tax payable by the unitholder with respect to such income) may exceed the cash actually distributed to the unitholder by us. At any time incentive distributions are made to the general partner, gross income will be allocated to the recipient to the extent of those distributions.

***Basis of Common Units***

A unitholder's initial tax basis for a common unit is generally the amount paid for the common unit. A unitholder's basis is generally increased by the unitholder's share of our income and decreased, but not below zero, by the unitholder's share of our losses and distributions.

***Limitations on Deductibility of Partnership Losses***

In the case of taxpayers subject to the passive loss rules (generally, individuals and closely held corporations), any partnership losses are only available to offset future income generated by us and cannot be used to offset income from other activities, including passive activities or investments. Any losses unused by virtue of the passive loss rules may be fully deducted if the unitholder disposes of all of the unitholder's common units in a taxable transaction with an unrelated party.

***Section 754 Election***

We have made the election provided for by Section 754 of the Code, which will generally result in a unitholder being allocated income and deductions calculated by reference to the portion of the unitholder's purchase price attributable to each asset of the Partnership.

***Disposition of Common Units***

A unitholder who sells common units will recognize gain or loss equal to the difference between the amount realized and the adjusted tax basis of those common units. A unitholder may not be able to trace basis to particular common units for this purpose. Thus, distributions of cash from us to a unitholder in excess of the income allocated to the unitholder will, in effect, become taxable income if the unitholder sells the common units at a price greater than the unitholder's adjusted tax basis even if the price is less than the unitholder's original cost. Moreover, a portion of the amount realized (whether or not representing gain) will be ordinary income.

***Foreign, State, Local and Other Tax Considerations***

In addition to federal income taxes, unitholders will likely be subject to other taxes, such as foreign, state and local income taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which a unitholder resides or in which we do business or own property. We own property and conduct business in Canada as well as in most states in the United States. A unitholder may be required to file Canadian federal income tax returns and to pay Canadian federal and provincial income taxes, as well as to file state income tax returns and to pay taxes in various states. A unitholder may be subject to penalties for failure to comply with such requirements. In certain states, tax losses may not produce a tax benefit in the year incurred (if, for example, we have no income from sources within that state) and also may not be available to offset income in subsequent taxable years. Some states may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the state. Withholding, the amount of which may be more or less than a particular unitholder's income tax liability owed to the state, may not relieve the nonresident unitholder from the obligation to file an income tax return. Amounts withheld may be treated as if distributed to unitholders for purposes of determining the amounts distributed by us.

*It is the responsibility of each prospective unitholder to investigate the legal and tax consequences, under the laws of pertinent states and localities, including the Canadian provinces and Canada, of the* *unitholder's investment in us. Further, it is the responsibility of each unitholder to file all U.S. federal, Canadian, state, provincial and local tax returns that may be required of the unitholder.*

### *Ownership of Common Units by Tax-Exempt Organizations and Certain Other Investors*

An investment in common units by tax-exempt organizations (including IRAs and other retirement plans), regulated investment companies (mutual funds) and foreign persons raises issues unique to such persons. Virtually all of our income allocated to a unitholder that is a tax-exempt organization is unrelated business taxable income and, thus, is taxable to such a unitholder. Furthermore, no significant amount of our gross income is qualifying income for purposes of determining whether a unitholder will qualify as a regulated investment company, and a unitholder who is a nonresident alien, foreign corporation or other foreign person is regarded as being engaged in a trade or business in the United States as a result of ownership of a common unit and, thus, is required to file federal income tax returns and to pay tax on the unitholder's share of our taxable income. Finally, distributions to foreign unitholders are subject to federal income tax withholding.

### *Tax Shelter Registration*

The Code generally requires that "tax shelters" be registered with the Secretary of the Treasury. We are registered as a tax shelter with the Secretary of the Treasury. Our tax shelter registration number is 99061000009. Issuance of the registration number does not indicate that an investment in the Partnership or the claimed tax benefits have been reviewed, examined or approved by the Internal Revenue Service.

## 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 the partnership's 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 have been 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.

## Available Information

We make available free of charge on our website (www.paalp.com) our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file the material with, or furnish it to, the Securities and Exchange Commission. We also have on our website our Code of Ethics for Senior Financial Officers. Any waiver of such Code will also be posted on our website. You can also access Section 16 reports through our website.

**Item 3.** ***Legal Proceedings***

*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.

*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.

**Item 4.** ***Submission of Matters to a Vote of Security Holders***

No matters were submitted to a vote of the security holders, through solicitation of proxies or otherwise, during the fiscal year covered by this report.

## PART II

**Item 5.** ***Market For the Registrant's Common Units and Related Unitholder Matters***

The common units, excluding the Class B common units, are listed and traded on the New York Stock Exchange under the symbol "PAA". On February 17, 2004, the closing market price for the common units was $32.12 per unit and there were approximately 30,000 record holders and beneficial owners (held in street name). As of February 17, 2004, there were 57,162,638 common units outstanding and 1,307,190 Class B common units outstanding. The number of common units outstanding on this date includes the 10,029,619 common units that converted from Subordinated Units in November 2003 and February 2004.

The following table sets forth high and low sales prices for the common units and the cash distributions paid per common unit for the periods indicated:

| | Common Unit Price Range | | |
|---|---|---|---|
| | High | Low | Cash Distributions[1] |
| **2002** | | | |
| 1st Quarter | $ 26.79 | $ 23.60 | $ 0.5250 |
| 2nd Quarter | 27.30 | 24.60 | 0.5375 |
| 3rd Quarter | 26.38 | 19.54 | 0.5375 |
| 4th Quarter | 24.44 | 22.04 | 0.5375 |
| **2003** | | | |
| 1st Quarter | $ 26.90 | $ 24.20 | $ 0.5500 |
| 2nd Quarter | 31.48 | 24.65 | 0.5500 |
| 3rd Quarter | 32.49 | 29.10 | 0.5500 |
| 4th Quarter | 32.82 | 29.76 | 0.5625 |

(1) Cash distributions are paid in the following calendar quarter.

The Class B common units are pari passu with common units with respect to quarterly 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 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, the Class B units have the same voting rights as the common units. As of February 17, 2004, there was one Class B unitholder.

***Cash Distribution Policy***

We distribute on a quarterly basis all of our available cash. Available cash generally means, for any of our fiscal quarters, all cash on hand at the end of the quarter less the amount of cash reserves that is necessary or appropriate in the reasonable discretion of our general partner to:

- provide for the proper conduct of our business;
- comply with applicable law, any of our debt instruments or other agreements; or
- provide funds for distributions to unitholders and our general partner for any one or more of the next four quarters.

In addition to distributions on its 2% general partner interest, 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, our general partner is entitled, without duplication, to 15% of amounts we distribute in excess of $0.450 per unit, 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. We paid $4.4 million to the general partner in incentive distributions in 2003. Our most recent quarterly distribution was $0.5625 per unit. See Item 13. "Certain Relationships and Related Transactions—Our General Partner."

Under the terms of the agreements governing our debt, we are prohibited from declaring or paying any distribution to unitholders if a default or event of default (as defined in such agreements) exists. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Credit Facilities and Long-term Debt."

See Item 12. "Security Ownership of Certain Beneficial Owners and Management and Related Unitholders' Matters" for equity compensation plan information.

## Item 6. *Selected Financial and Operating Data*

The historical financial information below for Plains All American Pipeline, L.P. was derived from our audited consolidated financial statements as of December 31, 2003, 2002, 2001, 2000 and 1999 and for the years ended December 31, 2003, 2002, 2001, 2000 and 1999. The selected financial data should be read in conjunction with the consolidated financial statements, including the notes thereto, and Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations."

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2003 | 2002 | 2001 | 2000 | 1999 |
| | (in millions except per unit data) | | | | |
| **Statement of operations data:** | | | | | |
| Revenues | $ 12,589.8 | $ 8,384.2 | $ 6,868.2 | $ 6,641.2 | $ 10,910.4 |
| Cost of sales and field operations (excluding LTIP charge) | 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] | 5.7 | — | — | — | — |
| General and administrative expenses (excluding LTIP charge) | 50.0 | 45.7 | 46.6 | 40.8 | 23.2 |
| LTIP charge—general and administrative[1] | 23.1 | — | — | — | — |
| Depreciation and amortization | 46.8 | 34.0 | 24.3 | 24.5 | 17.3 |
| Restructuring expense | — | — | — | — | 1.4 |
| Total costs and expenses | 12,492.3 | 8,289.6 | 6,796.8 | 6,578.8 | 11,008.4 |
| Gain on sale of assets | 0.6 | — | 1.0 | 48.2 | 16.4 |
| Operating income | 98.2 | 94.6 | 72.4 | 110.6 | (81.6) |
| Interest expense | (35.2) | (29.1) | (29.1) | (28.7) | (21.1) |
| Interest income and other, net[2] | (3.6) | (0.2) | 0.4 | (4.4) | 0.9 |
| Income (loss) from continuing operations before cumulative effect of accounting change | $ 59.4 | $ 65.3 | $ 43.7 | $ 77.5 | $ (101.8) |
| Basic net income (loss) per limited partner unit before cumulative effect of accounting change | $ 1.01 | $ 1.34 | $ 1.12 | $ 2.64 | $ (3.16) |
| Diluted net income (loss) per limited partner unit before cumulative effect of accounting change | $ 1.00 | $ 1.34 | $ 1.12 | $ 2.64 | $ (3.16) |
| Basic weighted average number of limited partner units outstanding | 52.7 | 45.5 | 37.5 | 34.4 | 31.6 |
| Diluted weighted average number of limited partner units outstanding | 53.4 | 45.5 | 37.5 | 34.4 | 31.6 |

*Table continued on following page.*

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2003 | 2002 | 2001 | 2000 | 1999 |
| | (in millions except per unit data) | | | | |
| **Balance sheet data (at end of period):** | | | | | |
| Working capital surplus (deficit) | $ (68.9) | $ (34.3) | $ 52.9 | $ 47.1 | $ 101.5 |
| Total assets | 2,095.6 | 1,666.6 | 1,261.2 | 885.8 | 1,223.0 |
| Total long-term debt(3)(4) | 519.0 | 509.7 | 354.7 | 320.0 | 424.1 |
| Total debt(4) | 646.2 | 609.0 | 456.2 | 321.3 | 482.8 |
| Partners' capital | 746.7 | 511.6 | 402.8 | 214.0 | 193.0 |

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2003 | 2002 | 2001 | 2000 | 1999 |
| **Other data (in millions):** | | | | | |
| Maintenance capital expenditures | $ 7.6 | $ 6.0 | $ 3.4 | $ 1.8 | $ 1.7 |
| Net cash provided by (used in) operating activities | 68.5 | 173.9 | (30.0) | (33.5) | (71.2) |
| Net cash provided by (used in) investing activities | (225.3) | (363.8) | (249.5) | 211.0 | (186.1) |
| Net cash provided by (used in) financing activities | 157.2 | 189.5 | 279.5 | (227.8) | 305.6 |
| Declared distributions per limited partner unit(5)(6)(7) | 2.19 | 2.11 | 1.95 | 1.83 | 1.59 |
| **Operating Data:** | | | | | |
| Volumes (thousands of barrels per day, unless otherwise noted)(8): | | | | | |
| Pipeline segment: | | | | | |
| Tariff activities | | | | | |
| All American | 59 | 65 | 69 | 74 | 103 |
| Basin | 263 | 93 | N/A | N/A | N/A |
| Other domestic(9) | 299 | 219 | 144 | 130 | 61 |
| Canada | 203 | 187 | 132 | N/A | N/A |
| Pipeline margin activities | 78 | 73 | 61 | 60 | 54 |
| Total | 902 | 637 | 406 | 264 | 218 |
| Gathering, marketing, terminalling and storage segment: | | | | | |
| Lease gathering | 437 | 410 | 348 | 262 | 265 |
| Bulk purchases(10) | 90 | 68 | 46 | 28 | 138 |
| Total | 527 | 478 | 394 | 290 | 403 |
| LPG sales | 38 | 35 | 19 | N/A | N/A |

(1) Compensation expense related to our Long Term Incentive Plan ("LTIP"), see Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Vesting of Restricted Units under Long-Term Incentive Plan."

(2) The 2000 period includes $15.1 million related to a loss on early extinguishment of debt previously classified as an extraordinary item. Effective with the issuance of Statement of Financial Accounting Standards ("SFAS") 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections" in April 2002, such items should now be shown as impacting income from continuing operations.

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

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

*Table continued on following page.*

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

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

(7) Our general partner is entitled to receive 2% proportional distributions and also incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. See Note 7 "Partners' Capital and Distributions" in the "Notes to the Consolidated Financial Statements."

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

(9) 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.

(10) 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.

## Item 7. *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. For more detailed information regarding the basis of presentation for the following financial information, see the "Notes to the Consolidated Financial Statements." Our discussion and analysis includes the following:

- Overview of Business and 2003 Results
- Acquisition Activities
- Critical Accounting Policies and Estimates
- Results of Operations
- Outlook
- Liquidity and Capital Resources

### Overview of Business and 2003 Results

*Company Overview*—Plains All American Pipeline, L.P. is a Delaware limited partnership (the "Partnership") formed in September of 1998. See Items 1 and 2. "Business and Properties—Organizational History." 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 in the United States and Canada of pipeline transportation, terminalling, storage and gathering assets in key oil producing basins and at major market hubs.

We are one of the largest midstream crude oil companies in North America, with approximately 7,000 miles of crude oil pipelines, approximately 24 million barrels of terminalling and storage capacity and a full complement of truck transportation and injection assets. On average, we handle over 1.6 million barrels per day of physical crude oil through our extensive network of assets located in major oil producing regions of the United States and Canada. Our operations are conducted primarily in Texas, Oklahoma, California, Louisiana and the Canadian provinces of Alberta and Saskatchewan and consist of two operating segments: (i) pipeline operations and (ii) gathering, marketing, terminalling and storage operations ("G M T& S"). Through our pipeline segment, we engage in interstate and intrastate crude oil pipeline transportation and certain related margin activities. Through our G M T & 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.

*Industry and Market Overview*—Crude oil market conditions during 2003 were extremely volatile as a confluence of several events caused the NYMEX benchmark price of crude oil to fluctuate widely. In addition, the crude oil market was in steep backwardation (prices for future deliveries were lower than prices for current deliveries) for much of the year. Crude oil production in the U.S. Midwest continues to decline while refinery demand remains stable to increasing. Generally, incremental barrels to this region must come from the south through Cushing or the Capline Pipeline System or from Canada to the north.

We anticipate that medium to long-term market dynamics in the crude oil industry will shift in a manner that will complement our asset base and business model, which is designed to deliver stable results in cyclical and volatile markets. We expect to see an increasingly more volatile market that will be subject to more frequent short-term swings in market prices and shifts in market structure. We believe these price swings and shifts in market structure could be much more pronounced than we have seen in the 20 or so years since crude oil was deregulated and began trading on the NYMEX. In addition, we anticipate that the crude oil supply and demand imbalance in the U.S. Midwest mentioned above will continue to intensify.

*2003 Operating Results Overview*—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. As a result of the conversions of our subordinated units into common units, approximately 326,000 phantom units granted under our Long-Term Incentive Plan vested in February 2004 and we anticipate that approximately 473,000 additional phantom units will vest in May 2004. During 2003, we accrued the majority of the estimated expense associated with the vesting of these units resulting in a charge of approximately $28.8 million.

- We completed a total of ten accretive and strategic transactions for aggregate consideration of $160 million. 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. Our historical acquisition activity is discussed under "—Acquisitions" immediately below.

- We realized year over year growth in segment profit from both our pipeline operations segment and our G M T& 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 G M T & S segment.

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

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

During 2003 we further strengthened our position by expanding our asset base through acquisition and internal growth projects. We will continue to pursue the purchase of midstream crude oil assets, and we will also continue to initiate projects designed to optimize crude oil flows in the areas in which we operate. Although we believe that we are well situated in the North American crude oil infrastructure, we face various operational, regulatory and financial challenges that may impact our ability to execute our strategy as planned. See "—Risk Factors Related to Our Business" for further discussion of these items.

## Acquisitions

We completed a number of acquisitions in 2003, 2002 and 2001 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.

### *2003 Acquisitions*

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

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

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

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

### *2002 Acquisitions*

*Shell West Texas Assets.* On August 1, 2002, we acquired interests in approximately 2,000 miles of gathering and mainline crude oil pipelines and approximately 8.9 million barrels (net to our interest) of above-ground crude oil terminalling and storage assets in West Texas from Shell Pipeline Company LP and Equilon Enterprises LLC (the "Shell acquisition") for approximately $324 million. The primary assets included in the transaction are interests in the Basin Pipeline System, the Permian Basin Gathering System and the Rancho Pipeline System. The entire purchase price was allocated to property and equipment.

The acquired assets are primarily fee-based mainline crude oil pipeline transportation assets that gather crude oil in the Permian Basin and transport the crude oil to major market locations in the Mid-Continent and Gulf Coast regions. The Permian Basin has long been one of the most stable crude oil producing regions in the United States, dating back to the 1930s. The acquired assets complement our existing asset infrastructure in West Texas and represent a transportation link to Cushing, Oklahoma, where we provide storage and terminalling services. In addition, we believe that the Basin Pipeline System is poised to benefit from potential shut-downs of refineries and other pipelines due to the shifting market dynamics in the West Texas area. The Rancho Pipeline System was taken out of service in March 2003, pursuant to the operating agreement. See Items 1 and 2. "Business and Properties—Acquisitions and Dispositions—Shutdown and Partial Sale of Rancho Pipeline System."

For more information on this transaction, as well as historical financial information on the businesses acquired and pro forma financial information reflecting the acquisition of the businesses, please refer to our Form 8-K dated August 9, 2002, which was filed with the Securities and Exchange Commission.

*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. 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—"Partners' Capital and Distributions" in the "Notes to the Consolidated Financial Statements"), resulting in aggregate consideration of approximately $73.9 million. The deferred consideration was recorded as 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 LPGs. The principal assets acquired include a crude oil handling facility, a 130,000-barrel tank facility, LPG facilities, existing business relationships and operating inventory. The acquired assets are part of our strategy to establish a Canadian operation that complements our operations in the United States. The purchase price, as adjusted 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 completed the acquisition of substantially all of the Canadian crude oil pipeline, gathering, storage and terminalling assets of Murphy Oil Company Ltd. for approximately $158.4 million in cash after post-closing adjustments, including financing and transaction costs (the "Murphy acquisition"). Initial financing for the acquisition was provided through borrowings under our credit facilities. The purchase price included $6.5 million for excess inventory in the pipeline systems. The principal assets acquired include approximately 560 miles of crude oil and condensate mainlines (including dual lines on which condensate is shipped for blending purposes and blended crude is shipped in the opposite direction) and associated gathering and lateral lines, approximately 1.1 million barrels of crude oil storage and terminalling capacity located primarily in Kerrobert, Saskatchewan, approximately 254,000 barrels of pipeline linefill and tank inventories, and 121 trailers used primarily for crude oil transportation. The acquired assets are part of our strategy to establish a Canadian operation that complements our operations in the United States.

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

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

| | |
|---|---|
| Crude oil pipeline, gathering and terminal assets | $ 148.0 |
| Pipeline linefill | 7.6 |
| Net working 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**

Our critical accounting policies are discussed in Note 2 to the Consolidated Financial Statements beginning on page F-8. 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 for 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 $1.0 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.

*Employee Incentive Plan Accrual*

We also make accruals for potential payments under our Long-Term Incentive Plan ("LTIP") when we determine that vesting of the common units granted under the LTIP is probable. The aggregate amount of the actual charge to expense will be determined by the unit price on the date vesting occurs (or, in some cases, the average unit price for a range of dates) multiplied by the number of units, plus our share of associated employment taxes. Uncertainties involved in this accrual include whether or not we actually achieve the specified performance requirements, the actual unit price at time of settlement and the continued employment of personnel subject to the vestings. A change in our unit price of $1 from the amount we used to record our accrual would have an impact of approximately $0.8 million on our operating income. 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.

**Results of Operations**

***Analysis of Operating Segments***

We evaluate segment performance based on (i) segment profit and (ii) maintenance capital. We define segment profit as revenues less (i) purchases, (ii) field operating costs and (iii) segment general and administrative ("G&A") expenses. Each of the items above excludes depreciation and amortization. As a master limited partnership, we make quarterly distributions of our "Available Cash" (as defined in our Partnership Agreement) to our unitholders. Therefore, we look at each period's earnings before non-cash depreciation and amortization as an important measure of segment performance. The exclusion of depreciation and amortization expense could be viewed as limiting the usefulness of segment profit as a performance measure because it does not account in current periods for the implied reduction in value of our capital assets, such as crude oil pipelines and facilities, caused by aging and wear and tear. Management compensates for this limitation by recognizing that depreciation and amortization are largely offset by repair and maintenance costs, which keep the actual value of our principal fixed assets from declining. These maintenance costs are a component of field operating costs included in segment profit or in maintenance capital, depending on the nature of the cost. Maintenance capital consists of capital expenditures required either to maintain the existing operating capacity of partially or fully depreciated assets or to extend their useful lives. Capital expenditures made to expand our existing capacity, whether through construction or acquisition, are not considered maintenance capital expenditures. Repair and maintenance expenditures associated with existing assets that do not extend the useful life or expand the operating capacity are charged to expense as incurred. See Note 15 "Operating Segments" in the "Notes to the Consolidated Financial Statements" for a reconciliation of segment profit to net income. 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 Operations | Gathering, Marketing, Terminalling & Storage Operations |
|---|---|---|
| | (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 judgement by management and will continue to be based on the business activities that exist during each period.

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

***Pipeline Operations***

As of December 31, 2003, we owned and operated approximately 7,000 miles of gathering and mainline crude oil pipelines located throughout the United States and Canada. Our activities from pipeline operations generally consist of transporting 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 costs of operating the pipeline. Segment profit from our pipeline capacity leases, barrel exchanges and buy/sell arrangements generally reflect a negotiated amount.

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

| | Year ended December 31, | | |
|---|---|---|---|
| | 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 (thousands of barrels per day)[3][4]** | | | |
| Tariff activities | | | |
| All American | 59 | 65 | 69 |
| Basin | 263 | 93 | — |
| 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 herein. 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)(2) | | | |
| 2003 acquisitions | 82 | — | — |
| 2002 acquisitions | 344 | 171 | — |
| 2001 acquisitions | 200 | 193 | 134 |
| All other pipeline systems | 198 | 200 | 211 |
| **Total tariff activities average daily volumes** | 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.

(2) 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.

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 Items 1 and 2. "Business and Properties—Acquisitions and Dispositions—Shutdown and Partial 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 revenues**[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 Items 1 and 2. "Business and Properties—Acquisitions and Dispositions—Shutdown and Partial 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. This amount is approximately equal to the threshold amounts we must incur before the sellers' indemnities take effect. 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.

***Gathering, Marketing, Terminalling and Storage Operations***

Our revenues from gathering and marketing activities reflect the sale of gathered and bulk purchased crude oil and LPG volumes, plus the sale of additional barrels exchanged through buy/sell arrangements entered into to supplement the margins of the gathered and bulk-purchased volumes. Because the commodities that we buy and sell are generally indexed to the same pricing indices for both the purchase and the sale, revenues and costs related to purchases will increase and decrease with changes in market prices without significant changes to our margins related to those purchases and sales. For example, our revenues 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. Although we believe that the combination of our lease gathering business and our storage assets provide a counter cyclical balance, which provides stability in our margins, these margins are not fixed and may vary from year to year. 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.

We own and operate approximately 24.0 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 11.0 million barrels of our 24.0 million barrels of tankage is used primarily in our Gathering, Marketing, Terminalling and Storage Operations and the balance is used in our Pipeline Operations segment. On a stand alone basis, segment profit from terminalling and storage activities is dependent on the throughput of volumes, the volume of crude oil stored and the level of fees generated from our terminalling and storage services. Our terminalling and storage activities are integrated with our gathering and marketing activities and the level of tankage that we allocate for our arbitrage activities (and therefore not available for lease to third parties) varies throughout crude oil price cycles. This integration enables us to use our storage tanks in an effort to counter-cyclically balance and hedge our gathering and marketing activities. In a contango market (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 operations and cash flows.

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 table sets forth our operating results from our Gathering, Marketing, Terminalling and Storage Operations 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** (thousands of barrels per day except as otherwise noted) (4)(5) | | | |
| Crude oil lease gathering | 437 | 410 | 348 |
| Crude oil bulk purchases | 90 | 68 | 46 |
| Total | 527 | 478 | 394 |
| LPG sales | 38 | 35 | 19 |

(1) Revenue and purchases include intersegment amounts.

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

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

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

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

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

- the overall counter-cyclical balance of our assets and the flexibility embedded in our business strategy;
- 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—Unallocated G&A Expense." 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 both 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 its floating rate debt. In addition, the average three-month LIBOR rate declined from approximately 1.8% during 2002 to approximately 1.2% during 2003. The net impact of these factors, increased commitment fees and changes in average debt balances decreased the average interest rate by 0.2%.

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 (See "—Liquidity and Capital Resources—Credit Facilities and Long-term Debt"). In addition, during the third quarter of 2003 we made a $34 million prepayment on our Senior secured term B loan in anticipation of the refinancing. The completion of these transactions resulted in a non-cash charge of approximately $3.3 million associated with the write-off of unamortized debt issue costs.

**Outlook**

*Crude Oil and LPG Inventory.* We value our crude oil and LPG inventory at the lower of cost or market, with cost determined using an average cost method. At December 31, 2003 we had approximately 3.7 million barrels of inventory classified as unhedged operating inventory at a weighted average cost of $25.41 per barrel. The lower of cost or market method requires a write down of inventory to the market price at the end of a period in which our weighted average cost exceeds the market price. This method does not allow a write up of the inventory if the market price subsequently increases. We did not have an adjustment in this period. However, future fluctuations in crude oil prices could result in a period end lower of cost or market adjustment.

*Ongoing Acquisition Activities.* Consistent with our business strategy, we are continuously engaged in discussions with potential sellers regarding the possible purchase by us of midstream crude oil assets. 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.

We are currently involved in advanced discussions with a potential seller regarding the purchase by us of crude oil pipeline, terminalling, storage and gathering and marketing assets for an aggregate purchase price, including assumed liabilities and obligations, ranging from $300 million to $400 million. Such transaction is subject to confirmatory due diligence, negotiation of a mutually acceptable definitive purchase and sale agreement, regulatory approval and approval of both our board of directors and that of the seller.

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 $0.4 million in deferred costs at December 31, 2003. We estimate that our deferred acquisition costs will increase in the first quarter of 2004 by approximately $0.7 million. 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.

On December 16, 2003, we entered into a definitive agreement to acquire all of Shell Pipeline Company LP's ("SPLC") interests in two entities. 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 667-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.

During 2003, average daily volumes on SPLC's interest in the Capline system were 125,000 barrels, a decrease from an average of 166,000 barrels per day in 2002 and 213,000 barrels per day in 2001. Effective December 1, 2003, SPLC modified its tariff structure in an effort to increase volume shipments on its space. On a month-to-month basis, average daily volumes on this system are subject to significant volatility. Our acquisition analysis assumed that the average daily volumes on the pipelines would be between 110,000 and 125,000 barrels per day, although it is possible that the volumes will decline below those levels.

The total purchase price for the transaction is approximately $158 million (approximately $142 million, net of the deposit paid). We have sufficient immediate availability under our revolving credit facilities to consummate this transaction. Consistent with our financial growth strategy of funding our acquisition growth with a balance of equity and debt, in December 2003, we issued approximately 2.8 million common units in anticipation of the consummation of this acquisition. See "—Liquidity and Capital Resources—Liquidity."

This acquisition is expected to close during the first quarter of 2004. While we believe it is reasonable to expect the acquisition to close in the first quarter of 2004, we can provide no assurance as to when or whether the acquisition will close.

*Basin Expansion.* In February 2004, we announced plans to expand a 345-mile section of the system. The section to be expanded extends from Colorado City, Texas to our Cushing Terminal. Upon the completion of this estimated $1.1 million expansion, the capacity of this section will increase approximately 15%, from 350,000 barrels per day to approximately 400,000 barrels per day.

*OCS Production.* In October 2003 Plains Exploration and Production announced that they had received all of the necessary permits to develop a portion of the Rocky Point structure that is accessible from the Point Arguello platforms and it appears that they will commence drilling activities in the second quarter of 2004. Such drilling activities, if successful, 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 assurances that our volumes transported would increase as a result of this drilling activity.

*Conversion of Subordinated Units and LTIP vesting.* In November of 2003, 25% of our outstanding subordinated units converted on a one-for-one basis into common units. During February 2004, the remaining subordinated units converted. As a result, distribution rights are now pari passu among all limited partner units. Further, as a result of these conversions, approximately 326,000 phantom units granted under our LTIP vested in February 2004, and we anticipate that another approximately 473,000 phantom units will vest in May 2004, subject to the satisfaction of service period requirements. We have accrued the majority of the estimated expense associated with the vesting of these units, however, we expect to incur an additional $1.9 million in the first quarter of 2004 and $0.6 million in the second quarter of 2004 primarily related to amortization of service period requirements. We expect to satisfy the May vesting of phantom units by paying cash for the settlement of approximately 201,000 phantom units in lieu of delivering common units and issuing approximately 181,000 common units (after netting for taxes) to satisfy the remainder of the vesting. See Item 11. "Executive Compensation—Long-Term Incentive Plan."

*FERC Quarterly Reporting.* On February 11, 2004 the FERC issued the final rules on quarterly reporting with, among other things, the addition of the FERC Form No. 6-Q Quarterly Financial Reporting of Oil Pipeline Companies. Our first filing will be due on July 23, 2004. The rules as finalized differ from the original proposal, and we are still analyzing the potential costs associated with compliance. It does not appear at this point that such costs will have a material effect on our financial condition or results of operations, but will add incrementally to our overall regulatory compliance costs.

*Sarbanes-Oxley Act and New SEC Rules.* Several regulatory and legislative initiatives were introduced in 2002 and 2003 in response to developments during 2001 and 2002 regarding accounting issues at large public companies, resulting disruptions in the capital markets and ensuing calls for action to prevent repetition of those events. Implementation of reforms in connection with these initiatives have added and will add to the costs of doing business for all publicly-traded entities, including the Partnership. These costs will have an adverse impact on future income and cash flow.

*Longer Term Outlook.* The partnership's 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 inventory capacity or, alternatively, will result in a reduction of existing inventory 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 shifts in market structure. In an environment of reduced inventories and tight supply and demand balances, even relatively minor supply disruptions can cause significant price swings. Conversely, despite a relatively balanced market on a global basis, competition within a given region of the U.S. could cause downward pricing pressure and significantly impact regional crude oil price differentials among crude oil grades and locations. Although we believe our business strategy is designed to manage these trends, factors and potential developments and that we are strategically positioned to benefit from certain of these developments, there can be no assurance that we will not be negatively affected.

## Liquidity and Capital Resources

### *Liquidity*

Cash generated from operations and our credit facilities are our primary sources of liquidity. At December 31, 2003, we had a working capital deficit of approximately $68.9 million and approximately $596.8 million of availability under our committed revolving credit facilities and approximately $100 million of availability under the hedged inventory facility. We completed several transactions in the fourth quarter of 2003 that increased our borrowing capacity and enhanced our liquidity position as of December 31, 2003. In November 2003, we refinanced our senior secured credit facilities with new senior unsecured credit facilities totaling $750 million and a $200 million uncommitted, senior secured facility for the purchase of hedged crude oil. We also completed the sale of $250 million of 5.625% senior notes in December of 2003, the proceeds of which were used to pay down outstanding balances on our revolving credit facilities. See "—Credit Facilities and Long-Term Debt." In addition, in anticipation of a potential pending acquisition, during December 2003, we completed a public offering of 2,840,800 common units priced at $31.94 per unit. Net proceeds from the offering, including our general partner's proportionate capital contribution and expenses associated with the offering, were approximately $88.4 million and were used to pay down outstanding balances on our revolving credit facilities.

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

### *Cash Flows*

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| | (in millions) | | |
| Cash provided by (used in): | | | |
| Operating activities | $ 68.5 | $ 173.9 | $ (30.0) |
| Investing activities | (225.3) | (363.8) | (249.5) |
| Financing activities | 157.2 | 189.5 | 279.5 |

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

Our positive cash flow from operations for 2003 resulted from cash generated by our recurring operations. A portion of these funds were used for crude oil linefill purchases of approximately

$47 million, primarily attributable to increased linefill requirements related to 2003 and 2002 acquisitions. 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 (i) the payment of approximately $74 million for crude oil purchased and stored during 2002 but for which receipt of the proceeds occurred during 2003 and (ii) crude oil linefill purchases of approximately $11 million. 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. In addition, we purchased approximately $13.7 million of crude oil linefill attributable to increased linefill requirements.

*Investing Activities.* Net cash used in investing activities in 2003, 2002 and 2001 consisted predominantly of cash paid for acquisitions. Net cash used in 2003 was $225.3 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 potential pending 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. Net cash used in 2002 was $363.8 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. Net cash used in 2001 was $249.5 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.

*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.

### *Universal Shelf*

We have filed with the Securities and Exchange Commission a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue from time to time up to an aggregate of $700 million of debt or equity securities. At December 31, 2003, we have approximately $165 million of remaining availability under this registration statement.

### *Credit Facilities and Long-term Debt*

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.

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 with the proceeds from the sale of such inventory. At December 31, 2003, we have approximately $100 million outstanding under our hedged crude oil inventory facility resulting in unused uncommitted capacity of approximately $100 million under this facility.

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:

- an interest coverage ratio that is not less than 2.75 to 1.0; and
- a debt coverage ratio which will not be greater than 4.5 to 1.0 on all outstanding debt and 5.25 to 1.0 on all outstanding debt during an acquisition period (generally, the period consisting of three fiscal quarters following an acquisition greater than $50 million).

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

A default under our credit facilities would permit the lenders to accelerate the maturity of the outstanding debt. As long as we are in compliance with our credit agreements, they do not restrict our ability to make distributions of "available cash" as defined in our partnership agreement. We are currently in compliance with the covenants contained in our credit facilities and indentures.

The average life of our long-term debt capitalization at December 31, 2003, was approximately 9 years. At the end of the year we had approximately $25.3 million of short-term working capital borrowings outstanding under our $425 million U.S. revolving credit facility, no amounts outstanding under our $125 million, 364-day revolving credit facility, no amounts outstanding under our $30 million Canadian working capital revolving credit facility, approximately $70.0 million outstanding under our $170 million Canadian revolving credit facility that matures in 2009, $200 million of senior notes that mature in 2012 and $250 million of senior notes that mature in 2013.

***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. 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. At December 31, 2003, we had received approximately $44.0 million of advance cash payments and prepayments from third parties to mitigate credit risk.

*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.

*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 Items 1 and 2. "—Business and Properties—Regulation—Pipeline and Storage Regulation."

Regulatory compliance costs include those related to pipeline integrity management (these are recurring expenses estimated to be approximately $1.8 million in 2004) and the adoption by the DOT of API 653 as the standard for the inspection, repair, alteration and reconstruction of jurisdictional storage tanks (these are recurring expenses estimated to be approximately $2 million in 2004). We will continue to refine our estimates as information from initial assessments becomes available. 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 pipeline integrity regulations and API 653 standards. The timing of such additional costs is uncertain and could vary materially from our current projections.

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.

*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. See Items 1 and 2. "Business and Properties—Operational Hazards and Insurance."

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

We may experience future releases of crude oil into the environment from our pipeline and storage operations, or discover past releases that were previously unidentified. Although we maintain an inspection program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to any such environmental releases from our assets may substantially affect our business.

***Capital Requirements***

We have made and will continue to make capital expenditures for acquisitions and expansion 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 $51.2 million on expansion capital projects during 2004. These projects include $22.5 million on upgrades related to prior acquisitions, $10.0 million on the Cushing Phase IV expansion, $6.0 million on the Iatan System expansion, $4.5 million on information systems related projects and $8.2 million on other operations projects. In addition to these expansion projects, we expect to spend approximately $142.2 million for the pending acquisition of interests in the Capline and Capwood Pipeline systems ($158.0 million including the $15.8 million deposit made in December 2003). In April 2004, we will make the contingent payment related to the CANPET acquisition, as discussed in Note 7—"Partners' Capital and Distributions" in the "Notes to the Consolidated Financial Statements." We also estimate we will spend approximately $11.7 million in maintenance capital during 2004.

***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-cancellable contractual obligations as of December 31, 2003, and our best estimate of the period in which the obligation will be settled (in millions):

| | 2004 | 2005 | 2006 | 2007 | 2008 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Long-term debt | $ — | $ — | $ — | $ — | $ — | $ 520.0 | $ 520.0 |
| Operating leases[(1)] | 12.7 | 11.2 | 8.8 | 5.3 | 2.8 | 0.7 | 41.5 |
| Capital expenditure obligations[(2)] | 154.7 | — | — | — | — | — | 154.7 |
| Other long-term liabilities[(3)(4)] | 10.9 | 3.2 | 1.2 | 0.6 | 0.4 | 0.7 | 17.0 |
| Total | $ 178.3 | $ 14.4 | $ 10.0 | $ 5.9 | $ 3.2 | $ 521.4 | $ 733.2 |

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

(2) Includes approximately $142.2 million for the Capline Acquisition.

(3) Approximately $10.9 million of the balance is related to the portion of our LTIP accrual that we anticipate settling with units in 2004.

(4) Excludes approximately $11.0 million non-current liability related to SFAS 133.

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 2003, these purchases averaged approximately $1.0 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 December 31, 2003, we had outstanding letters of credit of approximately $57.9 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 February 13, 2004, we paid a cash distribution of $0.5625 per unit on all outstanding units. 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 $2.3 million paid to our general partner for its general partner ($0.7 million) and incentive distribution interests ($1.6 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.

We paid $4.4 million to the general partner in incentive distributions in 2003. See Item 13. "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.

**Risk Factors 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. A 5,000 barrel per day decline in volumes shipped from these fields would result in a decrease in annual pipeline tariff revenues of approximately $3.3 million. 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.

*Potential future acquisitions and expansions, if any, may affect our business by substantially increasing the level of our indebtedness and contingent liabilities and increasing our risks of being unable to effectively integrate these new operations.*

From time to time, we evaluate and acquire assets and businesses that we believe complement our existing assets and businesses. Acquisitions may require substantial capital or the incurrence of substantial indebtedness. If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and you will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

*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, an average 10,000 barrel per day variance in the Basin Pipeline System, equivalent to an approximate 4% volume variance on that pipeline system, would result in an approximate $0.8 million change in annualized revenues less direct field operating costs.

*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 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. 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.

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

Our competitors include other crude oil pipelines, the major integrated oil companies, their marketing affiliates, and independent gatherers, brokers and marketers of widely varying sizes, financial resources and experience. Some of these competitors have capital resources many times greater than ours and control greater supplies of crude oil. A $0.01 per barrel variance in the aggregate average segment profit would have an approximate $2.0 million annual effect on segment profit.

*Newly acquired properties could expose us to environmental liabilities and increased regulatory compliance costs.*

Our business plan calls for a continuing acquisition program. Assets that we have acquired or may acquire in the future will likely have associated environmental liabilities, as well as required compliance with regulations such as the integrity maintenance program for regulated pipelines and the API 653 standard for regulated storage. Although we attempt to identify such exposures and address the associated costs through indemnities, purchase price adjustments or insurance, we may experience costs not covered by indemnity, insurance or reserves.

*The profitability of our gathering and marketing activities depends primarily 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 $1.1 million per year negative impact on segment profit. This impact is based on a reasonable margin throughout various market conditions. Actual margins vary based on the location of the crude oil, the strength or weakness of the market and the grade or quality of crude oil.

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

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

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

*In 1999, we suffered a large loss from unauthorized crude oil trading by a former employee. A loss of this kind could occur again in the future in spite of our best efforts to prevent it.*

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 not to acquire and hold crude oil, futures contracts or derivative products for the purpose of speculating on price changes. We discovered in November 1999 that this 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.

*Our operations are subject to federal and state environmental and safety laws and regulations relating to environmental protection and operational safety.*

Our pipeline, gathering, storage and terminalling operations are subject to the risk of incurring substantial environmental and safety related costs and liabilities. These costs and liabilities could arise under increasingly strict environmental and safety laws, including regulations and enforcement policies, or claims for damages to property or persons resulting from our operations. If we were not able to recover such resulting costs through insurance or increased tariffs and revenues, our cash flows and results of operations could be materially impacted.

The transportation and storage of crude oil results in a risk that crude oil and other hydrocarbons may be suddenly or gradually released into the environment, potentially causing substantial expenditures for a response action, significant government penalties, liability to government agencies for natural resources damages, liability to private parties for personal injury or property damages, and significant business interruption.

*Our Canadian pipeline assets are subject to federal and provincial regulation.*

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 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.

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

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

*The terms of our indebtedness may limit our ability to borrow additional funds, make distributions to unitholders, comply with the terms of our indebtedness or capitalize on business opportunities.*

As of December 31, 2003, our total outstanding long-term debt was approximately $519.0 million. Our payment of principal and interest on the debt will reduce the cash available for distribution on the units. Various limitations in our indebtedness may reduce our ability to incur additional debt, to engage in some transactions and to capitalize on business opportunities. Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions.

*Changes in currency exchange rates and foreign currency restrictions and shortages could adversely affect our operating results.*

Because we conduct operations outside the U.S., we are exposed to currency fluctuations and exchange rate risks that may adversely affect our results of operations. In addition, legal restrictions or shortages in currencies outside the U.S. may prevent us from converting sufficient local currency to enable us to comply with our currency placement obligations not denominated in local currency or to meet our operating needs and debt service requirements.

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

The after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. 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. Some or all of the distributions made to unitholders would be treated as dividend income, and no income, gains, losses or deductions would flow through to unitholders. Treatment of us as a corporation would cause a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of the common units. Moreover, treatment of us as a corporation would materially and adversely affect our ability to make payments on our debt securities.

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

**Item 7A.** ***Quantitative and Qualitative Disclosures About Market Risks***

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

*Commodity Price Risk*

We hedge our exposure to price fluctuations with respect to crude oil and LPG in storage, and expected purchases, sales and transportation of these commodities. The derivative instruments utilized consist primarily of futures and option contracts traded on the NYMEX and over-the-counter transactions, including crude oil swap and option contracts entered into with financial institutions and other energy companies (see Note 5 to our consolidated financial statements for a discussion of the mitigation of credit risk). 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 and an aggregate of 250,000 barrels of LPG.

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" in the "Notes to the Consolidated Financial Statements."

All of our open commodity price risk derivatives at December 31, 2003 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 | $ 7.5 | $ (6.4) |
| Swaps and options contracts | $ (3.3) | $ 2.2 |
| | | |
| LPG: | | |
| Futures contracts | $ — | $ — |
| Swaps and options contracts | $ (0.7) | $ 0.9 |

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, we utilize interest rate swaps and collars to hedge interest obligations on specific debt issuances, including anticipated debt issuances. The table below presents principal payments and the related weighted average interest rates by expected maturity dates for variable rate debt outstanding at December 31, 2003. The 7.75% senior notes issued during 2002 and the 5.625% senior notes issued during 2003 are fixed rate notes and their interest rates are not subject to market risk. Our variable rate debt bears interest at LIBOR, prime or the bankers acceptance plus the applicable margin. The average interest rates presented below are based upon rates in effect at December 31, 2003. 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 | $ 125.8 | $ — | $ — | $ — | $ — | $ — | $ 125.8 |
| Average interest rate | 2.3% | — | — | — | — | — | 2.3% |
| Long-term debt—variable rate | $ — | $ — | $ — | $ — | $ — | $ 70.0 | $ 70.0 |
| Average interest rate | — | — | — | — | — | 2.2% | 2.2% |

Interest rate swaps are used to hedge underlying interest payment obligations. We estimate the fair value of these instruments based on current termination values. These instruments hedge interest rates on specific debt issuances and qualify for hedge accounting. The interest rate differential is reflected as an adjustment to interest expense over the life of the instruments.

The table shown below summarizes the fair value of our interest rate swaps by the year of maturity (in millions):

| | Year of Maturity | | | | |
|---|---|---|---|---|---|
| | 2004 | 2005 | 2006 | 2007 | Total |
| Interest rate swaps | $ (0.4) | $ — | $ — | $ — | $ (0.4) |

At December 31, 2003, an interest rate swap with an aggregate notional principal amount of $50 million was outstanding. The interest rate swap is based on LIBOR rates and provides for a LIBOR rate of 4.3% for a $50.0 million notional principal amount expiring March 2004. Interest on the underlying debt being hedged is based on LIBOR plus a margin.

*Currency Exchange Risk*

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

Because a significant portion of our Canadian business is conducted in Canadian dollars, we use certain financial instruments to minimize the risks of changes in the exchange rate. These instruments include forward exchange contracts, forward extra option contracts and cross currency swaps. Additionally, at times, a portion of our debt is denominated in Canadian dollars. At December 31, 2003, we did not have any Canadian dollar debt. All of the financial instruments utilized are placed with large creditworthy financial institutions.

At December 31, 2003, we had forward exchange contracts that allow us to exchange $2.0 million Canadian for at least $1.5 million U.S. quarterly during 2004 (based on a Canadian dollar to U.S. dollar exchange rate of 1.33 to 1) and $1.0 million Canadian for at least $0.7 million U.S. quarterly during 2005 (based on a Canadian dollar to U.S. dollar exchange rate of 1.34 to 1). At 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. in May 2004 and May 2005 and has a final maturity in May 2006 ($19.0 million U.S.).

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

| | Year of Maturity | | | | |
|---|---|---|---|---|---|
| | 2004 | 2005 | 2006 | 2007 | Total |
| Forward exchange contracts | $ (0.3) | $ (0.1) | $ — | $ — | $ (0.4) |
| Cross currency swaps | (1.0) | (0.7) | (3.1) | — | (4.8) |
| Total | $ (1.3) | $ (0.8) | $ (3.1) | $ — | $ (5.2) |

**Item 8. *Financial Statements and Supplementary Data***

The information required here is included in the report as set forth in the "Index to Financial Statements" on page F-1.

**Item 9.** ***Changes In and Disagreements With Accountants on Accounting and Financial Disclosure***

None.

**Item 9A.** ***Controls and Procedures***

We maintain written "disclosure controls and procedures," which we refer to as our "DCP." The purpose of our DCP is to provide reasonable assurance that (i) information is recorded, processed, summarized and reported in time to allow for timely disclosure of such information in accordance with the securities laws and SEC regulations and (ii) information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow for timely decisions regarding required disclosure. Our DCP is incremental to our system of internal accounting controls designed to comply with the requirements of Section 13(b)(2) of the Exchange Act.

Applicable SEC rules require an evaluation of the effectiveness of the design and operation of our DCP, as of December 31, 2003, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Management (including our Chief Executive Officer and Chief Financial Officer) has evaluated the effectiveness of the design and operation of our DCP as of December 31, 2003, and has found our DCP to be effective in providing reasonable assurance of the timely recording, processing, summarization and reporting of information, and in accumulation and communication of information to management to allow for timely decisions with regard to required disclosure.

In addition to the information concerning our DCP, we are required to disclose certain changes in our internal control over financial reporting. There was no change in our internal control over financial reporting that occurred during the fourth quarter of 2003 and that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to Exchange Act rules 13a-14(a) and 15d-14(a) are filed with this report as exhibits 31.1 and 31.2. The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. §1350 are furnished with this report as exhibits 32.1 and 32.2.

## PART III

### Item 10. *Directors and Executive Officers of Our General Partner*

**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 the partnership 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, the 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 the Partnership, subject in all cases to any specific unitholder rights contained in the partnership agreement. Because we are a limited partnership, the new listing standards of the New York Stock Exchange, when effective, will 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. Mr. Symonds is 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 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 have a finance committee that advises and assists management with respect to financial matters. We also have a governance committee that is reviewing and revising our governance practices as appropriate in light of recent governance reform initiatives. 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. We currently have a standing conflicts committee consisting of two members who are not 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.

We have adopted a Code of Ethics for Senior Financial Officers. That code is available on our website.

**Report of the Audit Committee**

The audit committee of Plains All American GP LLC, acting in its capacity as the general partner of Plains All American Pipeline, L.P. (the "Partnership"), oversees the Partnership's financial reporting process on behalf of the board of directors. Management has the primary responsibility for the financial statements and the reporting process including the systems of internal controls.

In fulfilling its oversight responsibilities, the audit committee reviewed and discussed with management the audited financial statements contained in this Annual Report on Form 10-K.

The Partnership's independent public accountants, PricewaterhouseCoopers LLP, are responsible for expressing an opinion on the conformity of the audited financial statements with generally accepted accounting principles. The audit committee reviewed with PricewaterhouseCoopers LLP their judgment as to the quality, not just the acceptability, of the Partnership's accounting principles and such other matters as are required to be discussed with the audit committee under generally accepted auditing standards.

The audit committee discussed with PricewaterhouseCoopers LLP the matters required to be discussed by SAS 61 (Codification of Statement on Auditing Standards, AU § 380), as may be modified or supplemented. The committee received written disclosures and the letter from PricewaterhouseCoopers LLP required by Independence Standards Board No. 1, *Independence Discussions with Audit Committees*, as may be modified or supplemented, and has discussed with PricewaterhouseCoopers LLP its independence from management and the Partnership.

Based on the reviews and discussions referred to above, the audit committee recommended to the board of directors that the audited financial statements be included in the Annual Report on Form 10-K for the year ended December 31, 2003 for filing with the SEC.

Everardo Goyanes, Chairman

Arthur L. Smith

J. Taft Symonds

**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 will serve until August 2004, and will be 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 | Position with Our General Partner |
|---|---|---|
| Greg L. Armstrong(1) | 45 | Chairman of the Board, Chief Executive Officer and Director |
| Harry N. Pefanis | 46 | President and Chief Operating Officer |
| Phillip D. Kramer | 48 | Executive Vice President and Chief Financial Officer |
| George R. Coiner | 53 | Senior Group Vice President |
| W. David Duckett | 49 | President—PMC (Nova Scotia) Company |
| Mark F. Shires | 46 | Senior Vice President—Operations |
| Alfred A. Lindseth | 34 | Senior Vice President—Technology, Process & Risk Management |
| Jim G. Hester | 44 | Vice President—Acquisitions |
| Tim Moore | 46 | Vice President, General Counsel and Secretary |
| Tina L. Val | 35 | Vice President—Accounting and Chief Accounting Officer |
| Everardo Goyanes | 59 | Director and Member of Audit* and Conflicts Committees |
| Gary R. Petersen(1) | 57 | Director and Member of Compensation Committee* |
| John T. Raymond(1) | 33 | Director and Member of Finance Committee |
| Robert V. Sinnott(1) | 54 | Director and Member of Finance and Compensation Committees |
| Arthur L. Smith | 51 | Director and Member of Audit, Conflicts*, Governance* and Compensation Committees |
| J. Taft Symonds(1) | 64 | Director and Member of Finance*, Governance and Audit Committee |

* Indicates chairman of committee

(1) The Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC (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. 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., in which Mr. Raymond indirectly owns a limited partner interest. Sable Investments, L.P. is controlled by James M. Flores, the Executive Chairman of Plains Resources and also the Chairman and Chief Executive Officer of Plains Exploration and Production. 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. Mr. Symonds has been designated by Plains Resources, of which he is a director. See Item 12. "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.

*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.

*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.

*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.

*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 Nuevo Energy Company and Equus II Incorporated.

*John T. Raymond* has served as a director since June 2001. Mr. Raymond has served as President and Chief Executive Officer of Plains Resources Inc. since December 2002 and is President and Chief Operating Officer of Plains Exploration and Production. 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. 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 Plains Resources and Glacier Water Services, Inc. (a vended water company).

*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 and Cabot Oil & Gas Corporation and is a current director of Evergreen Resources, Inc. Mr. Smith holds the CFA designation. 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 has been Chairman of the Board of Symonds Trust Co. Ltd. (an investment firm) and Chairman of the Board of Maurice Pincoffs Company, Inc. (an international marketing firm) since 1978. He is also Chairman of the Board of Tetra Technologies, Inc. (an oilfield services firm) and a director of Plains Resources Inc. Mr. Symonds has a background in both investment and commercial banking. 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 | Position with Our General Partner/Canadian General Partner |
|---|---|---|
| **Management Team/Other Officers:** | | |
| A. Patrick Diamond | 31 | Manager—Special Projects |
| Lawrence J. Dreyfuss | 49 | 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.) |
| Al Swanson | 40 | Vice President and Treasurer |
| Troy Valenzuela | 43 | Vice President—Environmental, Health and Safety |
| John P. vonBerg | 49 | Vice President—Trading |
| **Canadian Officers:** | | |
| D. Mark Alenius | 44 | 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 | 43 | Vice President—Crude Oil 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.

*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.

*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.

*Troy 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 the partnership and its predecessors for the last 10 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 1992 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.

*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.

*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.

**Section 16(a) Beneficial Ownership Reporting Compliance**

Section 16(a) of the Securities and Exchange Act of 1934 requires directors, officers and persons who beneficially own more than ten percent of a registered class of our equity securities to file with the SEC and the New York Stock Exchange initial reports of ownership and reports of changes in ownership of such equity securities. Such persons are also required to furnish us with copies of all Section 16(a) forms that they file. Based solely upon a review of the copies of Forms 3, 4 and 5 furnished to us, or written representations from certain reporting persons that no Forms 5 were required, we believe that our officers and directors complied with all filing requirements with respect to transactions in our equity securities during 2003, except as follows: Mr. Petersen filed an Amended Form 4 to amend two previous Forms 4 that were otherwise timely filed. Mr. Petersen reported two acquisitions of indirect beneficial ownership of 1,250 units on June 8, 2002 and June 8, 2003, respectively, by the transfer of such units 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. Petersen disclaims beneficial ownership of such units.

### Item 11. *Executive Compensation*

### Summary Compensation Table

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 Item 13. "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<br>Chairman and CEO | 2003 | $ 330,000 | $ 1,000,000 | $ 12,000(2) | $ — |
| | 2002 | 330,000 | 600,000 | 11,000(2) | |
| | 2001 | 165,000(1) | 450,000 | (1) (2) | |
| Harry N. Pefanis<br>President and COO | 2003 | $ 235,000 | $ 800,000 | $ 12,000(2) | $ 452,400 |
| | 2002 | 235,000 | 475,000 | 11,000(2) | |
| | 2001 | 117,500(1) | 350,000 | (1) (2) | |
| Phillip D. Kramer<br>Executive V.P. and CFO | 2003 | $ 200,000 | $ 500,000 | $ 12,000(2) | $ — |
| | 2002 | 200,000 | 275,000 | 11,000(2) | |
| | 2001 | 100,000(1) | 100,000 | (1) (2) | |
| George R. Coiner<br>Senior Vice President | 2003 | $ 200,000 | $ 719,600(3) | $ 12,000(2) | $ 226,200 |
| | 2002 | 200,000 | 451,000(4) | 11,000(2) | |
| | 2001 | 175,000 | 430,100(5) | 10,500(2) | |
| W. David Duckett(6)<br>President—PMC (Nova Scotia) Company | 2003 | $ 190,658 | $ 724,883 | $ — | $ — |
| | 2002 | $ 163,891 | $ 270,070 | $ — | $ — |
| | 2001 | $ 80,020 | $ 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 Item 13. "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 Plains Resources Common Stock (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 primary term of Mr. Armstrong's employment agreement runs for three years from June 30, 2001. The term will be automatically extended by one year on each anniversary of the initial date (June 30, 2001) 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 primary term of Mr. Pefanis' employment agreement runs for three years from June 30, 2001. The term will be automatically extended by one year on each anniversary of the initial date (June 30, 2001) 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.

**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. 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 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 another approximately 473,000 additional phantom units will vest in May 2004, subject to the satisfication of service period requirements.

We paid cash in lieu of issuing units for approximately 111,000 of the phantom units that have vested to date. We have issued approximately 156,000 new common units (after netting for taxes) in satisfaction of vesting. We anticipate paying cash for approximately 201,000 of the phantom units expected to vest in May, as well as approximately 181,000 new common units (after netting for taxes) in connection with such vesting. As a result of the vesting of these awards, we recognized an expense of approximately $7.4 million as of September 30, 2003 and an expense of approximately $28.8 million as of December 31, 2003. Based on a probability assessment combined with an amortization of service period, we anticipate recognizing an expense of $1.9 million and $0.6 million in the first and second quarters of 2004.

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 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 and are payable in 25% increments on each anniversary of June 8, 2001. The first and second vestings took place on June 8, 2002 and June 8, 2003. See "—Compensation of Directors."

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

| | | November 2003 Vesting | | February 2004 Vesting | | May-04 Vesting (anticipated) | | Remaining Unvested Grants(3) | |
|---|---|---|---|---|---|---|---|---|---|
| **Name** | **Total Units** | **Units** | **Value(1)** | **Units** | **Value(1)** | **Units** | **Value(2)** | **Units** | **Value(2)** |
| Greg L. Armstrong | 70,000 | — | — | 17,500 | $ 551,250 | 17,500 | $ 568,050 | 35,000 | $ 1,136,100 |
| Harry N. Pefanis | 70,000 | 15,000 | $ 452,400 | 47,500 | $ 1,511,550 | 2,500 | $ 81,150 | 5,000 | $ 162,300 |
| Phillip D. Kramer | 50,000 | — | — | 12,500 | $ 393,750 | 12,500 | $ 405,750 | 25,000 | $ 811,500 |
| George R. Coiner | 67,500 | 7,500 | $ 226,200 | 31,875 | $ 1,028,869 | 9,375 | $ 304,313 | 18,750 | $ 608,625 |
| W. David Duckett | — | — | — | — | — | — | — | — | — |

(1) As of vesting date.

(2) Calculated as if vested and delivered, at a market value of $32.46 at the market close, on December 31, 2003.

(3) With respect to remaining grants, vesting is contingent upon the Partnership achieving specified distribution thresholds. For such remaining grants, 50% of the units require an annualized per unit distribution of $2.30 and 50% require an annualized distribution level of $2.50.

*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.

### 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. See Item 13. "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.

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 received a grant of 5,000 phantom units in 2002. The units vest and are payable in 25% increments annually on each anniversary of June 8, 2001. The first and second vestings occurred on June 8, 2002 and June 8, 2003.

### 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. The 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 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. See Item 13. "Certain Relationships and Related Transactions."

**Item 12.** ***Security Ownership of Certain Beneficial Owners and Management and Related Unitholders' Matters***

**Beneficial Ownership of Limited Partner Units**

Our common units and Class B common units outstanding represent 98% of our equity (limited partner interest). The 2% general partner interest is discussed separately below under the caption "Beneficial Ownership of General Partner Interest." The following table sets forth the beneficial ownership of limited partner units held by beneficial owners of 5% or more of the units, by directors and Named Executive Officers of our general partner and by all directors and executive officers as a group as of February 17, 2004.

| Name of Beneficial Owner | Common Units | Percentage of Common Units | Class B Common Units | Percentage of Class B Units | Percentage of Total Limited Partner Units(3) |
|---|---|---|---|---|---|
| Plains Resources Inc.(1)(2) | 11,087,912 | 19.4% | 1,307,190 | 100.0% | 21.20% |
| Greg L. Armstrong | 170,000(4)(5)(6) | (7) | — | — | (7) |
| Harry N. Pefanis | 129,689(5)(6) | (7) | — | — | (7) |
| George R. Coiner | 54,651(5)(6) | (7) | — | — | (7) |
| Phillip D. Kramer | 61,285(5)(6) | (7) | — | — | (7) |
| W. David Duckett | —(8) | — | — | — | — |
| Everardo Goyanes | 6,200 | (7) | — | — | (7) |
| Gary R. Petersen(9) | 1,550 | (7) | — | — | (7) |
| John T. Raymond(10) | 114,971 | — | — | — | (7) |
| Robert V. Sinnott(11) | 12,500 | (7) | — | — | (7) |
| Arthur L. Smith | 12,500 | (7) | — | — | (7) |
| J. Taft Symonds | 12,500 | (7) | — | — | (7) |
| All directors and executive officers as a group (16 persons) | 625,635(5)(6) | 1.1% | — | — | 1.2% |

(1) Plains Resources Inc. is the sole stockholder of Plains Holdings Inc., our former general partner. The record holder of the Class B Common Units is Plains Holdings Inc. The record holder of the common units is Plains Holdings II Inc., a wholly owned subsidiary of Plains Holdings Inc. The address of Plains Resources Inc., Plains Holdings Inc. and Plains Holdings II Inc. is 700 Milam, Suite 3100, Houston, Texas 77002.

(2) Includes common units owned by Plains Resources, to be transferred to certain of our employees (former Plains Resources employees), subject to certain vesting conditions. See "Certain Relationships and Related Transactions—Transactions with Related Parties—Stock Option Replacement."

(3) Limited partner units constitute 98% of our equity, with the remaining 2% held by our general partner. The beneficial ownership of our general partner is set forth in the table below under the caption "Beneficial Ownership of General Partner Interest." Giving effect to its indirect ownership of a portion of our general partner, Plains Resources Inc. owns approximately 21.7% of our total equity.

(4) Does not include the approximately 446,000 common units owned by our general partner, held for the purpose of satisfying its obligations under the Performance Option Plan. See Item 13. "Certain Relationships and Related Transactions—Transactions with Related Parties—Performance Option Plan." Mr. Armstrong disclaims any beneficial ownership of such units beyond his rights as a grantee under the plan.

(5) Does not include unvested phantom units granted under the LTIP, none of which will vest within 60 days of the date hereof. A substantial number of phantom units are expected to vest in early May of 2004. See Item 11. "Executive Compensation—Long-Term Incentive Plan."

Table continued on following page.

(6) Includes the following vested, unexercised options to purchase common units. Mr. Armstrong: 18,750; Mr. Pefanis: 13,750; Mr. Coiner: 10,625; Mr. Kramer: 11,250; directors and officers as a group: 66,875. See Item 13. "Certain Relationships and Related Transactions—Transactions with Related Parties—Performance Option Plan."

(7) Less than one percent.

(8) In April 2004, we anticipate making a contingent purchase price payment relating to our CANPET acquisition. This payment may be made in cash or common units. Mr. Duckett, as an owner of CANPET, will receive 37.8% of any common units issued. See Note 7 of "Notes to Consolidated Financial Statements."

(9) See note 1 to the table of Directors and Executive Officers under "—Directors and Executive Officers." Mr. Petersen disclaims any deemed beneficial ownership of any units owned by E-Holdings III, L.P. or other affiliates of EnCap Investments L.P. beyond his pecuniary interest. The address for E-Holdings III, L.P. is 1100 Louisiana, Suite 3150, Houston, Texas 77002.

(10) Units include 97,171 units contributed to Sable Holdings, L.P. by John T. Raymond in exchange for a limited partner interest. Mr. Raymond has the right to reacquire such units. See note 1 to the table of Directors and Executive Officers under "—Directors and Executive Officers." Mr. Raymond disclaims any deemed beneficial ownership of any units (other than the 97,171 units mentioned above) held by Sable Holdings, L.P. or its affiliates or Plains Resources or its affiliates.

(11) See note 1 to the table of Directors and Executive Officers under "—Directors and Executive Officers." Mr. Sinnott disclaims any deemed beneficial ownership of any units held by KAFU Holdings, L.P. or its affiliates, other than through his 4.5% limited partner interest in KAFU Holdings, L.P. The address for KAFU Holdings, L.P. is 1800 Avenue of the Stars, 2nd Floor, Los Angeles, California 90067.

**Beneficial Ownership of General Partner Interest**

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

| Name and Address of Owner | Percentage Ownership of Plains AAP, L.P. |
|---|---|
| Plains Resources Inc.[1]<br>700 Milam, Suite 3100<br>Houston, TX 77002 | 44.000% |
| Sable Investments, L.P.[2]<br>700 Milam, Suite 3100<br>Houston, TX 77002 | 20.000% |
| KAFU Holdings, L.P.[3]<br>1800 Avenue of the Stars, 2nd Floor<br>Los Angeles, CA 90067 | 16.418% |
| E-Holdings III, L.P.[4]<br>1100 Louisiana, Suite 3150<br>Houston, TX 77002 | 9.000% |

Table continued on following page.

| | |
|---|---|
| PAA Management, L.P.(5)<br>333 Clay Street, #1600<br>Houston, TX 77002 | 4.000% |
| Wachovia Investors, Inc.<br>301 South College Street, 12th Floor<br>Charlotte, NC 28288 | 3.382% |
| Mark E. Strome<br>100 Wilshire Blvd., Suite 1500<br>Santa Monica, CA 90401 | 2.134% |
| Strome Hedgecap Fund, L.P.<br>100 Wilshire Blvd., Suite 1500<br>Santa Monica, CA 90401 | 1.066% |

(1) Plains Resources Inc. is the sole stockholder of Plains Holdings Inc., which owns 44% of the equity of our general partner. Sable Investments, L.P. has entered into a voting agreement with Plains Holdings Inc. pursuant to which Sable has agreed to exercise Sable's right to designate a director under the Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC by designating its director in accordance with instructions from Plains Holdings. See Note 1 to the Directors and Executive Officers table under "—Directors and Executive Officers." The agreement is limited to such designations and the obligation to vote in favor of such designee.

(2) John T. Raymond has the right to acquire a 1% interest in our general partner from Sable Investments, L.P. See Note 1 to the Directors and Executive Officers table under "—Directors and Executive Officers." Mr. Raymond disclaims any deemed beneficial ownership of the interests held by Plains Resources Inc. or Sable Investments, L.P. beyond such right.

(3) See Note 1 to the Directors and Executive Officers table under "—Directors and Executive Officers." Mr. Sinnott disclaims any deemed beneficial ownership of the interests owned by KAFU Holdings, L.P. other than through his 4.5% limited partner interest in KAFU Holdings, L.P.

(4) See Note 1 to the Directors and Executive Officers table under "—Directors and Executive Officers." Mr. Petersen disclaims any deemed beneficial ownership of the interests owned by E-Holdings III, L.P. beyond his pecuniary interest.

(5) PAA Management, L.P. is owned entirely by certain members of senior management, including Messrs. Armstrong (approximately 27%), Pefanis (approximately 15%), Kramer (approximately 10%) and Coiner (approximately 10%). Other than Mr. Armstrong, no directors own any interest in PAA Management, L.P. Directors and executive officers as a group own approximately 80% of PAA Management, L.P. Mr. Armstrong disclaims any beneficial ownership of the general partner interest owned by Plains AAP, L.P., other than through his ownership interest in PAA Management, L.P.

On November 20, 2003, Plains Resources (which owns all of the equity of Plains Holdings Inc.) announced that it had received a proposal from Vulcan Capital, along with James C. Flores and John T. Raymond, to acquire all of Plains Resources' outstanding stock for $14.25 per share in cash. Vulcan Capital is an investment vehicle for investor Paul G. Allen. Plains Resources also announced that its board of directors had formed a special committee to evaluate the proposal. On December 1, 2003, Vulcan and Messrs. Allen, Flores and Raymond filed a Schedule 13D with the Securities and Exchange Commission in connection with the proposed buyout. On February 19, 2004, Plains Resources announced that the special committee of its board of directors had recommended that the board of directors accept a revised offer of $16.75 per share. The February 19 announcement further indicated that Plains Resources' board of directors had accepted the special committee's recommendation, approved a merger agreement and recommended that shareholders vote in favor of the transaction. Prior to the November announcement, we have received assurances from Mr. Flores, Mr. Raymond and representatives of Vulcan that if the proposed buyout is consummated, there is no intent to merge or otherwise combine the interests of Plains Holdings Inc. and Sable Investments, L.P. We cannot predict whether the stockholders of Plains Resources will approve the transaction or whether a competing transaction may be offered or considered.

**Equity Compensation Plan Information**

| Plan Category | Number of units to be issued upon exercise/vesting of outstanding options, warrants and rights* | Weighted average exercise price of outstanding options, warrants and rights | Number of units remaining available for future issuance under equity compensation plans* |
|---|---|---|---|
| | (a) | (b) | (c) |
| Equity compensation plans approved by unitholders: | | | |
| 1998 Long Term Incentive Plan | 956,588(1) | N/A(2) | (1)(3) |
| Equity compensation plans not approved by unit holders: | | | |
| 1998 Long Term Incentive Plan | (1)(4) | N/A(2) | (5) |
| Performance Option Plan | (6) | $ 17.30(7) | (8) |

* As of December 31, 2003

(1) Our general partner has adopted and maintains a Long Term Incentive Plan for our officers, employees and directors. As originally instituted by our former general partner prior to our IPO, the LTIP contemplated awards of up to 975,000 phantom units. Upon vesting, these awards could be satisfied either by (i) primary issuance of units by us or (ii) cash settlement or purchase of units by our general partner with the cost reimbursed by us. In 2000, the LTIP was amended, as provided in the plan, without unitholder approval to increase the maximum awards to 1,425,000 phantom units; however, we can issue no more than 975,000 new units to satisfy the awards. Any additional units must be purchased by our general partner in the open market or in private transactions and be reimbursed by us. In November 2003, we issued 18,412 units in satisfaction of vesting under the LTIP. The number of units (956,588) presented in column (a) subtracts the units issued in November and assumes that all remaining grants will be satisfied by the issuance of new units upon vesting. In fact, a substantial number of phantom units that vested in February of 2004 were satisfied without the issuance of units. These phantom units were settled in cash or withheld for taxes. See Item 11. "Executive Compensation—Long-Term Incentive Plan." Any units not issued upon vesting can become "available for future issuance" under column (c).

(2) Phantom unit awards under the LTIP vest without payment by recipients. See Item 11. "Executive Compensation—Long-Term Incentive Plan—Restricted Unit Plan."

(3) In accordance with Item 201(d) of Regulation S-K, this column (c) excludes the securities disclosed in column (a). However, as discussed in footnote (1) above, any phantom units represented in column (a) that are not satisfied by the issuance of units become "available for future issuance." After giving effect to the vesting of phantom units in February 2004 and the anticipated vesting in May of 2004, we estimate that there will be approximately 211,000 phantom units outstanding and approximately 427,000 units available for future issuance (excluding phantom units outstanding). See Item 11. "Executive Compensation—Long-Term Incentive Plan."

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

(5) Awards for up to 450,000 phantom units may be granted under the portion of the LTIP not approved by unitholders; however, no common units are "available for future issuance" under the plan, because all such awards must be satisfied with cash or out of units purchased by our general partner and reimbursed by us.

(6) Our general partner has adopted and maintains a Performance Option Plan for officers and key employees pursuant to which optionees have the right to purchase units from the general partner. The units that will be sold under the plan were contributed to the general partner by certain of its owners in connection with the General Partner Transition without economic cost to the Partnership. Thus, there will be no units "issued upon exercise/vesting of outstanding options." Approximately 375,000 unit options have been granted out of the 450,000 units originally available under the plan. See footnote (8) below and Item 13. "Certain Relationships and Related Parties—Performance Option Plan."

(7) The current strike price for all outstanding options under the Performance Option Plan is $17.30 per unit. The strike price decreases as distributions are paid. Future grants may include different pricing elements. See Item 13. "Certain Relationships and Related Parties—Performance Option Plan."

(8) In connection with the General Partner Transition, certain of the investors in our general partner contributed 450,000 subordinated units (now converted into common units) to our general partner to fund the Performance Option Plan. Options for approximately 372,000 units are currently outstanding and approximately 75,000 units are available for future option grants.

For a narrative description of the material features of the LTIP and the Performance Option Plan, see Item 11. "Executive Compensation—Long-Term Incentive Plan" and Item 13. "Certain Relationships and Related Transactions—Transactions with Related Parties—Performance Option Plan."

## Item 13. *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 | $ 108,000 | $ 2,204 | $ 110,204 | 2.0% |
| $ 2.00 | $ 120,000 | $ 4,510 | $ 124,510 | 3.6% |
| $ 2.20 | $ 132,000 | $ 8,510 | $ 140,510 | 6.1% |
| $ 2.40 | $ 144,000 | $ 12,510 | $ 156,510 | 8.0% |
| $ 2.60 | $ 156,000 | $ 16,510 | $ 172,510 | 9.6% |
| $ 2.80 | $ 168,000 | $ 24,510 | $ 192,510 | 12.7% |
| $ 3.00 | $ 180,000 | $ 36,510 | $ 216,510 | 16.9% |

(1) In thousands.

(2) Assumes 60,000,000 units outstanding. Actual number of units outstanding as of the date hereof are 58,469,828. 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.

Plains Resources currently owns an effective 44% of our general partner interest, as well as approximately 21.2% of our outstanding limited partner units. Mr. John Raymond, one of our directors, is President and Chief Executive Officer of Plains Resources. Mr. Raymond was designated as a member of our board by Sable Investments, L.P., which is controlled by Mr. James Flores. Mr. Flores is the Executive Chairman of Plains Resources. 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 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.

- 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 the majority of Plains Resources equity production for a fee of $0.20 per barrel. The fee is subject to adjustment every three years 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. In November 2001, the agreement automatically extended for an additional three-year period. 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. We are in the process of negotiating an amended agreement to reflect the separation of Plains Resources and one of its subsidiaries, discussed below. 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 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 (or the substance of the Omnibus Agreement) to terminate.

On December 18, 2002, Plains Resources completed a spin-off of one of its subsidiaries, Plains Exploration and Production ("PXP") to its shareholders. Mr. Raymond is President and Chief Operating Officer of PXP. 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. We are in the process of negotiating the terms of an amended agreement with PXP.

***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 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 currently permits the grant of restricted 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.

A restricted unit is a "phantom" unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit. As of February 17, 2004, aggregate grants of approximately 187,000 common units have been issued or purchased and delivered upon vesting and approximately 680,000 phantom units remain outstanding to employees, officers and directors of our general partner. See Item 11. "Executive Compensation—Long-Term Incentive Plan."

***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. Of this amount, 75,000, 55,000, 45,000 and 42,500 were granted to Messrs. Armstrong, Pefanis, Kramer and Coiner, respectively, and approximately 278,000 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, 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 was $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.

***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 (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 grant included 8,548, 4,602 and 9,742 units to Messrs. Armstrong, Pefanis and Kramer, respectively. The units vest 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 administers 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 have 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. 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—"Partners' Capital and Distributions" in the "Notes to the Consolidated Financial Statements"), resulting in aggregate consideration of approximately $73.9 million. 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 will receive a proportionate share of the proceeds from any contingent payment of purchase price for the CANPET assets.

***Tank Car Lease and CANPET***

In connection with the CANPET asset 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.

***Other***

An affiliate of Wachovia Investors, Inc., which owns a portion of our general partner interest, participated as an underwriter in our December offering of units and earned underwriting discounts and commissions of approximately $614,000. An affiliate of KAFU Holdings, L.P., another owner of our general partner interest, also participated in that offering, earning commissions of approximately $340,000. An affiliate of Wachovia Investors, Inc. is also a lender under our bank credit facility.

## Item 14. *Principal Accountant Fees and Services*

All services provided by our independent auditor are subject to pre-approval by our Audit Committee. The Audit Committee has instituted a policy that describes certain pre-approved non-audit services. We believe that the description of services is designed to be sufficiently detailed as to particular services provided, such that (i) management is not required to exercise judgment as to whether a proposed service fits within the description and (ii) the Audit Committee knows what services it is being asked to pre-approve. The Audit Committee is informed of each engagement of the independent auditor to provide services under the policy.

The following table details expenditures paid to our independent auditor (in thousands):

| | Year Ended December 31, | |
|---|---|---|
| | 2003 | 2002 |
| Audit fees | $ 852 | $ 748 |
| Audit-related fees | 147 | 265 |
| Tax fees | 401 | 381 |
| All other fees | 315 | 690 |
| Total | $ 1,715 | $ 2,084 |

Expenditures classified as Audit fees above include those related to our annual audit, audits of our general partner and certain joint ventures of which we are the operator, and work performed on our registration of publicly-held debt and equity. Audit related fees are primarily comprised of work performed related to our benefit plans and "carve-outs" of acquired companies. The expenditures related to tax processing as well as the preparation of Form K-1 for our unitholders are included in Tax fees. All other fees consist of those associated with due diligence performed on potential acquisitions and certain risk management projects.

## PART IV

**Item 15.** ***Exhibits, Financial Statement Schedules and Reports on Form 8-K***

**(a)(1) and (2) Financial Statements and Financial Statement Schedules**

See "Index to the Consolidated Financial Statements" set forth on Page F-1.

All schedules are omitted because they are not applicable, or the required information is shown in the consolidated financial statements or notes thereto.

**(a)(3) Exhibits**

| | | |
|---|---|---|
| 3.1 | — | Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. dated as of June 27, 2001, (incorporated by reference to Exhibit 3.1). |
| 3.2 | — | Second Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. dated as of June 27, 2001 (incorporated by reference to Exhibit 3.2 to Form 8-K filed August 27, 2001). |
| 3.3 | — | Second Amended and Restated Agreement of Limited Partnership of All American Pipeline, L.P. dated as of June 27, 2001 (incorporated by reference to Exhibit 3.3 Form 8-K filed August 27, 2001). |
| 3.4 | — | Certificate of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.4 to Registration Statement, file No. 333-64107). |
| 3.5 | — | Certificate of Limited Partnership of Plains Marketing, L.P. dated as of November 10, 1998 (incorporated by reference to Exhibit 3.5 to Annual Report on Form 10-K for the Year Ended December 31, 1998). |
| 3.6 | — | Articles of Conversion of All American Pipeline Company dated as of November 10, 1998 (incorporated by reference to Exhibit 3.5 to Annual Report on Form 10-K for the Year Ended December 31, 1998). |
| 3.7 | — | Amended and Restated Limited Partnership Agreement of Plains AAP, L.P., dated as of June 8, 2001 (incorporated by reference to Exhibit 3.1 to Form 8-K filed June 11, 2001). |
| 3.8 | — | Amended and Restated Limited Liability Company Agreement of Plains All American GP, LLC dated as of June 8, 2001, as amended by first Amendment dated September 16, 2003 (incorporated by reference to Exhibit 3.1 to Quarterly Form 10-Q for the period ended September 30, 2003). |
| 4.1 | — | Registration Rights Agreement, dated as of June 8, 2001, among Plains All American Pipeline, L.P., Sable Holdings, L.P., E-Holdings III, L.P., KAFU Holdings, LP, PAA Management, L.P., Mark E. Strome, Strome Hedgecap Fund, L.P., John T. Raymond and Plains All American Inc. (incorporated by reference to Exhibit 4.1 to Form 8-K filed June 11, 2001). |
| 4.2 | — | Indenture dated as of September 25, 2002 (incorporated by reference to Exhibit 4.1 to Quarterly Report on Form 10-Q for the Quarter ended September 30, 2002). |
| 4.3 | — | First Supplemental Indenture dated as of September 25, 2002 (incorporated by reference to Exhibit 4.2 to Quarterly Report on Form 10-Q for the Quarter ended September 30, 2002). |
| †4.4 | — | Second Supplemental Indenture dated as of December 10, 2003. |
| †4.5 | — | Registration Rights Agreement dated December 10, 2003. |

| | | |
|---|---|---|
| 10.01 | — | Contribution, Assignment and Amendment Agreement, dated as of June 27, 2001, among Plains All American Pipeline, L.P., Plains Marketing, L.P., All American Pipeline, L.P., Plains AAP, L.P., Plains All American GP LLC and Plains Marketing GP Inc. (incorporated by reference to Exhibit 10.1 to Form 8-K filed June 27, 2001). |
| 10.02 | — | Contribution, Assignment and Amendment Agreement, dated as of June 8, 2001, among Plains All American Inc., Plains AAP, L.P. and Plains All American GP LLC (incorporated by reference to Exhibit 10.1 to Form 8-K filed June 11, 2001). |
| 10.03 | — | Separation Agreement, dated as of June 8, 2001 among Plains Resources Inc., Plains All American Inc., Plains All American GP LLC, Plains AAP, L.P. and Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 10.2 to Form 8-K filed June 11, 2001). |
| 10.04 | — | Pension and Employee Benefits Assumption and Transition Agreement, dated as of June 8, 2001 among Plains Resources Inc., Plains All American Inc. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to Form 8-K filed June 11, 2001). |
| **10.05 | — | Plains All American GP LLC 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 99.1 to Registration Statement on Form S-8, File No. 333-74920) as amended June 27, 2003 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the period ended June 30, 2003). |
| **10.06 | — | Plains All American 2001 Performance Option Plan (incorporated by reference to Exhibit 99.2 to Registration Statement on Form S-8, File No. 333-74920). |
| **10.07 | — | Phantom MLP unit Agreement for Greg L. Armstrong (incorporated by reference to Exhibit 99.3 to Registration Statement on Form S-8, File No. 333-74920). |
| **10.08 | — | Phantom MLP Unit Agreement for Phillip D. Kramer (incorporated by reference to Exhibit 99.5 to Registration Statement on Form S-8, File No. 333-74920). |
| **10.09 | — | Phantom MLP Unit Agreement for Tim Moore (incorporated by reference to Exhibit 99.6 to Registration Statement on Form S-8, File No. 333-74920). |
| **10.10 | — | Phantom MLP Unit Agreement for Harry N. Pefanis (incorporated by reference to Exhibit 99.7 to Registration Statement on Form S-8, File No. 333-74920). |
| **10.11 | — | Amended and Restated Employment Agreement between Plains All American GP LLC and Greg L. Armstrong dated as of June 30, 2001 (incorporated by reference to Exhibit 10.3 to Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2001). |
| **10.12 | — | Amended and Restated Employment Agreement between Plains All American GP LLC and Harry N. Pefanis dated as of June 30, 2001 (incorporated by reference to Exhibit 10.4 to Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2001). |
| 10.13 | — | Asset Purchase and Sale Agreement between Murphy Oil Company Ltd. And Plains Marketing Canada, L.P. (incorporated by reference to Form 8-K filed May 10, 2001). |
| 10.14 | — | Crude Oil Marketing Agreement among Plains Resources Inc., Plains Illinois Inc., Stocker Resources, L.P., Calumet Florida, Inc. and Plains Marketing, L.P. dated as of November 23, 1998 (incorporated by reference to Exhibit 10.07 to Annual Report on Form 10-K for the Year Ended December 31, 1998). |

| | | |
|---|---|---|
| 10.15 | — | Omnibus Agreement among Plains Resources Inc., Plains All American Pipeline, L.P., Plains Marketing, L.P., All American Pipeline, L.P., and Plains All American Inc. dated as of November 23, 1998 (incorporated by reference to Exhibit 10.08 to Annual Report on Form 10-K for the Year Ended December 31, 1998). |
| 10.16 | — | Transportation Agreement dated July 30, 1993, between All American Pipeline Company and Exxon Company, U.S.A. (incorporated by reference to Exhibit 10.9 to Registration Statement, file No. 333-64107). |
| 10.17 | — | Transportation Agreement dated August 2, 1993, between All American Pipeline Company and Texaco Trading and Transportation Inc., Chevron U.S.A. and Sun Operating Limited Partnership (incorporated by reference to Exhibit 10.10 to Registration Statement, File No. 333-64107). |
| 10.18 | — | First Amendment to Contribution, Conveyance and Assumption Agreement dated as of December 15, 1998 (incorporated by reference to Exhibit 10.13 to Annual Report on Form 10-K for the Year Ended December 31, 1998). |
| 10.19 | — | Agreement for Purchase and Sale of Membership Interest in Scurlock Permian LLC between Marathon Ashland LLC and Plains Marketing, L.P. dated as of March 17, 1999 (incorporated by reference to Exhibit 10.16 to Annual Report on Form 10-K for the Year Ended December 31, 1998). |
| †10.20 | — | 364-Day Revolving Credit Agreement dated November 21, 2003 among Plains All American Pipeline, L.P and Fleet National Bank and certain other lenders. |
| †10.21 | — | Uncommitted Senior Secured Discretionary Contango Credit Agreement dated November 21, 2003 among Plains Marketing, L.P. and Fleet National Bank and certain other lenders. |
| †10.22 | — | US/Canada Revolving Credit Agreement dated November 21, 2003 among Plains All American Pipeline, L.P, PMC (Nova Scotia) Company, Plains Marketing Canada, L.P. and Fleet National Bank and certain other lenders. |
| *23.1 | — | Consent of Independent Registered Public Accounting Firm |
| *31.1 | — | Certification of Principal Executive Officer pursuant to Exchange Act rules 13a-14(a) and 15d-14(a) |
| *31.2 | — | Certification of Principal Financial Officer pursuant to Exchange Act rules 13a-14(a) and 15d-14(a) |
| *32.1 | — | Certification of Chief Executive Officer pursuant to 18 U.S.C. § 1350. |
| *32.2 | — | Certification of Chief Financial Officer pursuant to 18 U.S.C. § 1350 |

† Previously filed

* Filed herewith

** Management contract or compensatory plan or arrangement

**(b) Reports on Form 8-K**

A Current Report on Form 8-K was furnished on February 24, 2004, in connection with disclosure of first quarter estimates and earnings guidance.

A Current Report on Form 8-K was filed on January 15, 2004 with an unaudited balance sheet of Plains AAP, L.P., as of September 30, 2003, attached as an exhibit.

A Current Report on Form 8-K was filed on December 22, 2003 with an underwriting agreement for an equity offering attached as an exhibit.

A Current Report on Form 8-K was filed on December 17, 2003 in connection with our disclosure of entering into an agreement to purchase the interests of Shell Pipeline Company' L.P.'s interests in certain pipeline systems.

A Current Report on Form 8-K was filed and furnished on December 17, 2003 in connection with our disclosure of the status of our acquisition activities.

A Current Report on Form 8-K was furnished on December 9, 2003, in connection with disclosure of our presentation at the Wachovia Securities Pipeline Conference and Symposium.

A Current Report on Form 8-K was furnished on December 3, 2003, in connection with the private offering of $250 million of 5.625% senior notes.

A Current Report on Form 8-K/A was furnished on October 29, 2003 to correct certain inaccuracies in the Current Report furnished on October 28, 2003.

A Current Report on Form 8-K was furnished on October 28, 2003, in connection with disclosure of our third-quarter results and fourth-quarter forecasts.

A Current Report on Form 8-K was furnished on October 7, 2003, in connection with our disclosure of our presentation at the IPAA's 2003 Oil & Gas Investment Symposium West.

A Current Report on Form 8-K was furnished on September 24, 2003, in connection with our disclosure of our presentation at the Herold's 12th Annual Pacesetters Energy Conference.

A Current Report on Form 8-K was furnished on September 16, 2003, in connection with our disclosure of our presentation at the RBC Capital Markets North American Energy and Power Conference.

A Current Report on Form 8-K was filed on September 10, 2003 with an underwriting agreement for an equity offering attached as an exhibit.

A Current Report on Form 8-K was furnished on September 8, 2003, in connection with the announcement of an equity offering.

## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

**PLAINS ALL AMERICAN PIPELINE, L.P.**

By: PLAINS AAP, L.P.,
its general partner

By: PLAINS ALL AMERICAN GP LLC,
its general partner

| | |
|---|---|
| Date: July 16, 2004 | By: /s/ GREG L. ARMSTRONG |
| | **Greg L. Armstrong, Chairman of the Board, Chief Executive Officer and Director of Plains All American GP LLC (Principal Executive Officer)** |
| Date: July 16, 2004 | By: /s/ PHILLIP D. KRAMER |
| | **Phillip D. Kramer, Executive Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial Officer)** |

**PLAINS ALL AMERICAN PIPELINE, L.P.**

**INDEX TO THE CONSOLIDATED FINANCIAL STATEMENTS**

**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 Company'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), which 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

## 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) |
| 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** | | | |
| 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) |
| Pipeline linefill | (46,790) | (11,060) | (13,736) |
| 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 | 68,518 | 173,894 | (29,953) |
| **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) |
| Proceeds from sales of assets | 8,450 | 1,437 | 740 |
| Net cash used in investing activities | (225,325) | (363,781) | (249,491) |
| **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 | — |
| 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.

*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 | 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.

*Other Litigation.* 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.

*Other*

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

We may experience future releases of crude oil into the environment from our pipeline and storage operations, or discover past releases that were previously unidentified. Although we maintain an inspection program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to any such environmental releases from our assets may substantially affect our business.

**Note 13—Environmental Remediation**

In connection with various acquisitions, we have received indemnities from the sellers for environmental exposure, subject to our prior payment of certain threshold amounts. Based on our investigations of the assets acquired in such acquisitions, we have identified several sites that exceed the threshold limitations under the various indemnities. Although we have not yet determined the total cost of remediation of these sites, we believe our indemnification arrangements should prevent such costs from having a material adverse effect on our financial condition, results of operations or cash flows.

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

As of December 31, 2003, we have approximately $6.6 million reserved associated with our remediation obligations. This amount is approximately equal to the threshold amounts the partnership must incur before the sellers' indemnities take effect. Approximately $1.6 million of our environmental reserve is classified as current and $5.0 million is classified as long-term because in many cases, the actual cash expenditures may not occur for up to ten years or more.

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

**Note 14—Quarterly Financial Data (Unaudited):**

| | First Quarter | Second Quarter | Third Quarter | Fourth Quarter | Total[1] |
|---|---|---|---|---|---|
| | (in thousands, except per unit data) | | | | |
| ***2003*** | | | | | |
| Revenues | $ 3,281.9 | $ 2,709.2 | $ 3,053.7 | $ 3,545.0 | $ 12,589.8 |
| Gross margin | 46.7 | 44.0 | 38.7 | 41.2 | 170.6 |
| Operating income | 33.6 | 31.9 | 21.0 | 11.6 | 98.2 |
| Net income (loss) | 24.4 | 23.4 | 11.9 | (0.2) | 59.4 |
| Basic net income (loss) per limited partner unit | 0.46 | 0.42 | 0.20 | (0.03) | 1.01 |
| Diluted net income (loss) per limited partner unit | 0.46 | 0.42 | 0.19 | (0.03) | 1.00 |
| Cash distributions per common unit[2] | $ 0.550 | $ 0.550 | $ 0.550 | $ 0.563 | $ 2.21 |
| ***2002*** | | | | | |
| Revenues | $ 1,545.3 | $ 1,985.3 | $ 2,344.1 | $ 2,509.5 | $ 8,384.2 |
| Gross margin | 31.4 | 34.5 | 35.3 | 39.0 | 140.2 |
| Operating income | 20.8 | 23.4 | 23.8 | 26.7 | 94.6 |
| Net income | 14.3 | 17.0 | 16.3 | 18.9 | 65.3 |
| Basic and diluted net income per limited partner unit | 0.31 | 0.37 | 0.33 | 0.35 | 1.34 |
| Cash distributions per common unit[2] | $ 0.525 | $ 0.538 | $ 0.538 | $ 0.538 | $ 2.14 |

(1) The sum of the four quarters may not equal the total year due to rounding.

(2) Represents cash distributions declared per common unit for the period indicated. Distributions were paid in the following calendar quarter.

**Note 15—Operating Segments**

Our operations consist of two operating segments: (1) Pipeline Operations—engages in interstate and intrastate crude oil pipeline transportation and certain related merchant activities; (2) Gathering, Marketing, Terminalling and Storage Operations—engages in purchases and resales of crude oil and LPG at various points along the distribution chain and the operation of certain terminalling and storage assets. We evaluate segment performance based on (i) segment profit and (ii) 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. 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 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. 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 exclude depreciation and amortization):

| | Pipeline | Gathering Marketing, Terminalling & Storage | Total |
|---|---|---|---|
| | | (in millions) | |
| **Twelve Months Ended December 31, 2003** | | | |
| Revenues: | | | |
| External Customers | $ 605.1 | $ 11,984.7 | $ 12,589.8 |
| Intersegment[(a)] | 53.5 | 0.9 | 54.5 |
| Total revenues of reportable segments | $ 658.6 | $ 11,985.6 | $ 12,644.3 |
| Segment profit[(c)] | $ 81.3 | $ 63.1 | $ 144.4 |
| Capital expenditures | $ 211.9 | $ 21.9 | $ 233.8 |
| Total assets | $ 1,221.0 | $ 874.6 | $ 2,095.6 |
| Non-cash SFAS 133 impact[(b)] | $ — | $ 0.4 | $ 0.4 |
| Maintenance capital | $ 6.4 | $ 1.2 | $ 7.6 |
| **Twelve Months Ended December 31, 2002** | | | |
| Revenues: | | | |
| External Customers | $ 462.4 | $ 7,921.8 | $ 8,384.2 |
| Intersegment[(a)] | 23.8 | — | 23.8 |
| Total revenues of reportable segments | $ 486.2 | $ 7,921.8 | $ 8,408.0 |
| Segment profit[(c)] | $ 70.7 | $ 58.9 | $ 129.6 |
| Capital expenditures | $ 341.9 | $ 23.3 | $ 365.2 |
| Total assets | $ 1,030.7 | $ 635.9 | $ 1,666.6 |
| Non-cash SFAS 133 impact[(b)] | $ — | $ 0.3 | $ 0.3 |
| Maintenance capital | $ 3.4 | $ 2.6 | $ 6.0 |
| **Twelve Months Ended December 31, 2001** | | | |
| Revenues: | | | |
| External Customers | $ 339.9 | $ 6,528.3 | $ 6,868.2 |
| Intersegment[(a)] | 17.5 | — | 17.5 |
| Total revenues of reportable segments | $ 357.4 | $ 6,528.3 | $ 6,885.7 |
| Segment profit[(c)] | $ 58.9 | $ 42.5 | $ 101.4 |
| Capital expenditures | $ 169.8 | $ 80.4 | $ 250.2 |
| Total assets | $ 472.3 | $ 788.9 | $ 1,261.2 |
| Non-cash SFAS 133 impact[(b)] | $ — | $ 0.2 | $ 0.2 |
| Maintenance capital | $ 0.5 | $ 2.9 | $ 3.4 |

(a) Intersegment sales were conducted at arms length.

Table continued on following page

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

(c) The following table reconciles segment profit to consolidated net income (in millions):

| | For the year ended December 31, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| Segment profit | $ 144.4 | $ 129.6 | $ 101.4 |
| Unallocated general and administrative expenses | — | (1.0) | (5.7) |
| Depreciation and amortization | (46.8) | (34.1) | (24.3) |
| Gain on sale of assets | 0.6 | — | 1.0 |
| Interest expense | (35.2) | (29.1) | (29.1) |
| Interest income and other, net | (3.6) | (0.1) | 0.4 |
| Cumulative effect of accounting change | — | — | 0.5 |
| Net Income | $ 59.4 | $ 65.3 | $ 44.2 |

*Geographic Data*

We have operations in the United States and Canada. Set forth below are revenues and long lived assets attributable to these geographic areas (in millions):

| | For the Year Ended December 31, | |
|---|---|---|
| **Revenues** | **2003** | **2002** |
| United States | $ 10,536.8 | $ 6,941.7 |
| Canada | 2,053.0 | 1,442.5 |
| | $ 12,589.8 | $ 8,384.2 |

| | For the Year Ended December 31, | |
|---|---|---|
| **Long-Lived Assets** | **2003** | **2002** |
| United States | $ 1,039.8 | $ 866.9 |
| Canada | 316.9 | 194.1 |
| | $ 1,356.7 | $ 1,061.0 |

**Note 16—Subsequent Events (Unaudited)**

*Link Acquisition.* On April 1, 2004, we completed the acquisition of substantially all of the North American crude oil and pipeline operations of Link Energy LLC ("Link") for approximately $330 million, including $273 million of cash, the assumption of $49 million of liabilities and $8 million of transaction, closing and integration costs and other items. 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 acquisition was funded with cash on hand, borrowings under a new $200 million 364-day credit facility and borrowings under our existing revolving credit facilities. The new credit facility contains a twelve-month term out option, exercisable at our election, at the end of the primary term, bears interest at a rate of LIBOR plus a margin ranging from ..625% to 1.25%, depending upon our credit rating, and includes essentially the same covenants as our existing credit facilities. On April 15, we completed the private placement of 3,245,700 units of Class C Common Units for $30.81 per unit to a group of institutional investors. Total proceeds from the transaction, after deducting transaction costs and including the general partner's proportionate contribution, were approximately $101 million and was used to reduce the balance outstanding under our existing revolving credit facilities. The partnership has committed to use net proceeds from future debt and equity offerings to retire or reduce the amount outstanding under the new $200 million 364-day credit facility.

On April 2, 2004, the Office of the Attorney General of Texas 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 indicated their investigation was prompted by complaints received from allegedly interested industry parties regarding the potential impact on competition in the Permian Basin area of West Texas. We understand that similar complaints have been received by the Federal Trade Commission, and that, consistent with federal-state protocols for conducting joint merger investigations, appropriate federal and state antitrust authorities are coordinating their activities. We are cooperating fully with the antitrust enforcement authorities.

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**EXHIBIT 23.1**

**CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (Nos. 333-91141, 333-54118, 333-74920) and Form S-3 (Nos. 333-59224, 333-68446) of Plains All American Pipeline, L.P. of our report dated February 26, 2004 relating to the consolidated financial statements, which appears in this Form 10-K/A Amendment No. 1.

/s/ PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP

Houston, TX
July 16, 2004

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**EXHIBIT 31.1**

**CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER**

**PLAINS ALL AMERICAN PIPELINE, L.P.**

I, Greg L. Armstrong, certify that:

1. I have reviewed this annual report on Form 10-K/A of Plains All American Pipeline, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) [intentionally omitted pursuant to SEC Release No. 34-47986];

   (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end the period covered by this report based on such evaluation; and

   (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 16, 2004

/s/ GREG L. ARMSTRONG

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Greg L. Armstrong
Chief Executive Officer

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CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER PLAINS ALL AMERICAN PIPELINE, L.P.

**EXHIBIT 31.2**

**CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER**

**PLAINS ALL AMERICAN PIPELINE, L.P.**

I, Phil Kramer, certify that:

1. I have reviewed this annual report on Form 10-K/A of Plains All American Pipeline, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) [intentionally omitted pursuant to SEC Release No. 34-47986];

(c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end the period covered by this report based on such evaluation; and

(d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 16, 2004

/s/ PHIL KRAMER

Phil Kramer
Chief Financial Officer

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**EXHIBIT 32.1**

**CERTIFICATION OF**
**CHIEF EXECUTIVE OFFICER**
**OF PLAINS ALL AMERICAN PIPELINE, L.P.**
**PURSUANT TO 18 U.S.C. § 1350**

I, Greg L. Armstrong, Chief Executive Officer of Plains All American Pipeline, L.P. (the "Company"), hereby certify that:

(i) the accompanying report on Form 10-K/A for the period ending December 31, 2003 and filed with the Securities and Exchange Commission on the date hereof (the "Report") by the Company fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ GREG L. ARMSTRONG

| | |
|---|---|
| Name: | Greg L. Armstrong |
| Date: | July 16, 2004 |

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**EXHIBIT 32.2**

**CERTIFICATION OF**
**CHIEF FINANCIAL OFFICER**
**OF PLAINS ALL AMERICAN PIPELINE, L.P.**
**PURSUANT TO 18 U.S.C. § 1350**

I, Phil Kramer, Chief Financial Officer of Plains All American Pipeline, L.P. (the "Company"), hereby certify that:

(i) the accompanying report on Form 10-K/A for the period ending December 31, 2003 and filed with the Securities and Exchange Commission on the date hereof (the "Report") by the Company fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ PHIL KRAMER

| | |
|---|---|
| Name: | Phil Kramer |
| Date: | July 16, 2004 |

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