PREMCOR INC
Form S-1/A
January 23, 2003
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As filed with the Securities and Exchange Commission on January 23, 2003

Registration No. 333-102087

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

AMENDMENT NO. 2
TO

FORM S-1
REGISTRATION STATEMENT

UNDER
THE SECURITIES ACT OF 1933

PREMCOR INC.

(Exact Name of Registrant as Specified in Its Charter)

Delaware	2911	43-1851087
(State or other jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Number)	(I.R.S. Employer Identification Number)

1700 East Putnam Avenue
Suite 500
Old Greenwich, Connecticut 06870
(203) 698-7500
(Address, including zip code, and telephone number, including area code, of Registrant s principal executive offices)

Michael D. Gayda, Esq.
Premcor Inc.
1700 East Putnam Avenue
Suite 500
Old Greenwich, Connecticut 06870
(203) 698-7500
(Name, address, including zip code, and telephone number, including area code, of agent for service)

With copies to:

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

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

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

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

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

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

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

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

PROSPECTUS (Subject to Completion)
Issued January 23, 2003

11,500,000 Shares

COMMON STOCK

Premcor Inc. is offering 11,500,000 shares of its common stock.

Our common stock is listed on the New York Stock Exchange under the symbol PCO. On January 21, 2003, the reported last sale price of our common stock on the New York Stock Exchange was $21.44 per share.

Investing in our common stock involves risks. See Risk Factors beginning on page 11.

PRICE $ A SHARE

	Price to Public	***Underwriting Discounts and Commissions***	***Proceeds to Premcor Inc.***
Per Share	$	$	$
Total	$	$	$

We have granted the underwriters the right to purchase up to an additional 1,725,000 shares to cover over-allotments.

The Securities and Exchange Commission and state securities regulators have not approved or disapproved these securities, or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

Morgan Stanley & Co. Incorporated expects to deliver the shares of common stock to purchasers on , 2003.

MORGAN STANLEY
CREDIT SUISSE FIRST BOSTON
DEUTSCHE BANK SECURITIES

GOLDMAN, SACHS & CO.

, 2003

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[Inside front cover artwork and graphics:

At the top of the page is a heading with the words Premcor Inc. Refining Assets Base . At the center of the page is a map showing the location of our two refineries and our terminal, and four third-party owned pipelines we use. In the upper right corner, there is a photograph of our Lima, Ohio refinery accompanied by the caption Lima refinery complex Lima, Ohio ; in the lower left corner, there is a photograph of our Port Arthur, Texas refinery accompanied by the caption Port Arthur refinery complex Port Arthur, Texas ; in the lower right corner, there is a photograph of a portion of our Port Arthur, Texas refinery accompanied by the caption Port Arthur heavy oil upgrade project Port Arthur, Texas . Below this photograph, in the extreme lower right hand corner, is the legend for the map which contains the following text: Premcor Refineries , Premcor Terminal and Third-party owned Pipelines .]

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You should rely only on the information contained in this prospectus. We have not authorized anyone to provide you with information different from that contained in this prospectus. We are offering to sell, and seeking offers to buy, shares of common stock only in jurisdictions where offers and sales are permitted. The information contained in this prospectus is accurate only as of the date of this prospectus, regardless of the time of delivery of this prospectus or any sale of the common stock.

PROSPECTUS SUMMARY

This summary may not contain all the information that may be important to you. You should read the entire prospectus, including the Risk Factors section and our financial statements and notes to those statements, before deciding whether to buy our common stock. As used in this prospectus, the terms we, our, or us refer to Premcor Inc. and its consolidated subsidiaries, taken as a whole, and our predecessors, unless the context otherwise indicates. Premcor Inc. should be distinguished from its subsidiaries, including Premcor USA Inc., The Premcor Refining Group Inc. and Port Arthur Finance Corp., each of which has publicly traded debt outstanding. Because of the technical nature of our industry, we have included a Glossary of Selected Terms that explains many of the terms we use in this prospectus.

PREMCOR INC.

Overview

We are one of the largest independent petroleum refiners and suppliers of unbranded transportation fuels, heating oil, petrochemical feedstocks, petroleum coke and other petroleum products in the United States. We currently own and operate refineries in Port Arthur, Texas and Lima, Ohio with a combined crude oil volume processing capability, known as throughput capacity, of approximately 420,000 barrels per day, or bpd. In late September 2002, we ceased refining operations at our Hartford, Illinois refinery and we are currently pursuing all strategic options with respect to the refinery. We sell petroleum products in the Midwest, the Gulf Coast, eastern and southeastern United States. We sell our products on an unbranded basis to approximately 750 distributors and chain retailers through our own product distribution system and an extensive third-party owned product distribution system, as well as in the spot market.

Our Port Arthur refinery has the capacity to process substantial volumes of low-cost high-sulfur and high-density crude oil, known as sour and heavy sour crude oil. This results in lower feedstock costs and creates a distinct competitive advantage. For the nine months ended September 30, 2002, light products accounted for approximately 90% of our total product volume. For the same period, high-value, premium product grades, such as high octane and reformulated gasoline, low-sulfur diesel and jet fuel, which are the most valuable types of light products, accounted for approximately 40% of our total product volume.

We had revenue of $6.4 billion in 2001, a decrease of 12% compared to 2000. During 2001, our net income available to common stockholders was $142.6 million, an increase of $62.5 million compared to 2000, and our adjusted EBITDA was $635.1 million, an increase of $416.6 million compared to 2000. Adjusted EBITDA for 2001 represents EBITDA excluding $167.2 million of charges related to the closure of our Blue Island, Illinois refinery and $9.0 million of other charges. We had revenue of $4.8 billion for the nine months ended September 30, 2002, a 7% decrease compared to the corresponding period in the previous year. For the nine months ended September 30, 2002, our net loss to common stockholders was $164.3 million compared to net income available to common stockholders of $187.1 million in the corresponding period in the previous year. For the nine months ended September 30, 2002, our adjusted EBITDA was $75.4 million compared to $636.1 million in the corresponding period in the previous year. Adjusted EBITDA excluded charges of $172.9 million and $176.2 million for the nine months ended September 30, 2002 and 2001, respectively, principally related to the closure of the Hartford and Blue Island refineries. For further detail on our results of operations, see Management s Discussion and Analysis of Financial Condition and Results of Operations.

The Transformation of Premcor

Beginning in early 1995 and continuing after Blackstone Capital Partners III Merchant Banking Fund L.P. and its affiliates, or Blackstone, acquired its controlling interest in us in 1997, we completed several strategic

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initiatives that have significantly enhanced our competitive position, the quality of our assets, and our financial and operating performance. For example:

- We divested non-core assets during 1998 and 1999, generating net proceeds of approximately $325 million, which we reinvested into our refining business.
- We increased our net crude oil throughput capacity from approximately 130,000 bpd to 420,000 bpd after closing two refineries by acquiring our Lima and Port Arthur refineries and subsequently upgrading our Port Arthur refinery.
- We implemented capital projects to increase throughput and premium product yields and to reduce operating expenses within our refining asset base. These projects, together with our acquisitions, increased our coking capacity from 18,000 bpd to 113,000 bpd, increased our cracking capacity from 70,000 bpd to 178,000 bpd, and increased our capacity to process heavy sour crude oil from 45,000 bpd to 200,000 bpd.
- We implemented a number of programs which increased the reliability of our operations and improved our safety performance, resulting in a reduction of our recordable injury rate from 3.12 to 1.14 per 200,000 hours worked.
- We expanded and enhanced our capabilities to supply fuels, on an unbranded basis, to include the Midwest, Gulf Coast, eastern and southeastern United States.
- We reduced our operating costs, which resulted in a reduction of our ratio of refining employees per thousand barrels from 7.2 to 3.4.

In February 2002, we recruited Mr. Thomas D. O Malley, a chief executive officer with a proven track record of successfully operating businesses and growing and enhancing shareholder value. Since then, Mr. O Malley has assembled a management team of energy and refining industry veterans to lead our company and our competitive position has continued to improve as a result of the following:

- We raised $481.7 million in an initial public offering of 20.7 million shares of our common stock and a concurrent private placement of 850,000 shares of our common stock in May 2002.
- We repaid $579.0 million of our subsidiaries long-term debt.
- We completed an internal restructuring in June 2002, which resulted in Sabine River Holding Corp. becoming our wholly-owned subsidiary.
- We ceased refining operations at our Hartford, Illinois refinery in late September 2002 after concluding it was uneconomical to reconfigure the refinery to meet new federally mandated fuel specification standards.
- We entered into an agreement with The Williams Companies, Inc. and certain of its subsidiaries in November 2002 for the purchase of their Memphis, Tennessee refinery and related supply and distribution assets.
- We have taken, and are continuing to take, steps to reduce our operating and general and administrative costs.

For further detail on our transformation, see Business The Transformation of Premcor.

Market Trends

We believe that the outlook for the United States refining industry is attractive due to certain significant trends that we have identified. We believe that:

- The supply and demand fundamentals for refined petroleum products have improved since the late 1990s and will continue to improve.

- Increasing worldwide supplies of lower-cost sour and heavy sour crude oil will provide an increasing cost advantage to those refineries with complex configurations that are able to process these crude oils.

- Products meeting new and evolving fuel specifications will account for an increasing share of total fuel demand, which will benefit refiners possessing the capabilities to blend and process these fuels.

- The continuing consolidation in the refining industry should create further attractive opportunities to acquire competitive refining capacity.

For further detail on market trends, see Business Market Trends.

Competitive Strengths

As a result of our transformation, we have developed the following strengths:

- As a pure-play refiner, which is a refiner without crude oil exploration and production or retail sales operations, we are free to supply our products to markets having the greatest profit potential and to focus our management attention and capital solely on refining.

- Our Port Arthur and Lima refineries are logistically well-located modern facilities of significant size and scope with access to a wide variety of crude oils and product distribution systems.

- Our Port Arthur refinery has significant heavy sour crude oil processing capacity, giving us a cost advantage over other refiners that are not able to process high volumes of these less expensive crude oils.

- We have a long-term heavy sour crude oil supply agreement with an affiliate of Petroleos Mexicanos, or PEMEX, the Mexican state oil company, that contains a mechanism intended to provide us with a minimum average coker gross margin and to moderate fluctuations in coker gross margins.

- We have an experienced and committed management team led by Thomas D. O Malley, a refining industry veteran with a proven track record of growing businesses and shareholder value through acquisitions.

For further detail on our competitive strengths, see Business Competitive Strengths.

Business Strategies

Our goal is to be a premier independent refiner and supplier of unbranded petroleum products in the United States and to be an industry leader in growing shareholder value. We intend to accomplish this goal, grow our business, enhance earnings and improve our return on capital by executing the following strategies:

- We intend to grow through timely and cost-effective acquisitions and by undertaking discretionary capital projects to improve, upgrade and potentially expand our refineries.

- We will continue to promote excellence in safety and reliability at our operations.

- We intend to create an organization in which employees are highly motivated to enhance earnings and improve return on capital.

For further detail on our business strategies, see Business Business Strategies.

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Memphis Refinery Acquisition

On November 25, 2002, we executed an agreement with The Williams Companies, Inc. and certain of its subsidiaries to purchase their Memphis, Tennessee refinery and related supply and distribution assets. The purchase price for the refinery and the other assets is $315 million, plus the value of inventories at closing. At current price levels, the value of the inventories is estimated to be $200 million. The agreement also provides for contingent participation, or earn-out, payments that could result in additional payments of $75 million by us to Williams over the next seven years, depending on the level of industry refining margins during that period.

The Memphis refinery has a rated crude oil throughput capacity of 190,000 bpd but typically processes approximately 170,000 bpd. The related assets include two truck-loading racks; three petroleum terminals in the area; supporting pipeline infrastructure that transports both crude oil and refined products; crude oil tankage at St. James, Louisiana; and an 80 megawatt power plant adjacent to the refinery.

We believe we are acquiring a quality refinery at an attractive price that will produce operating and economic synergies and that should be accretive to our earnings per share and generate positive cash flow from operations. Completion of the acquisition is subject to our obtaining the requisite financing and the satisfaction of customary conditions, including regulatory approvals. We intend to finance the acquisition with the proceeds from this offering and the other financing transactions described below. We expect the acquisition to close during the first quarter of 2003.

Other Financing Transactions

Debt Financing. Concurrently with this offering, our subsidiary, The Premcor Refining Group Inc., or PRG, is offering $400 million aggregate principal amount of senior notes due 2010 and 2013. The senior notes are being offered in an offering that is exempt from the registration requirements of the Securities Act. This prospectus shall not be deemed to be an offer to sell or a solicitation of an offer to buy the senior notes.

Neither the offering made hereby nor the debt financing is contingent on the other or upon the closing of the Memphis refinery acquisition. However, the debt financing is contingent upon us obtaining various waivers and approvals under, and extending the maturity date of, our credit agreement. See Description of Indebtedness The Premcor Refining Group Credit Agreement.

Private Equity Commitment. We have the right to sell in a private placement up to $65 million of our common stock to Blackstone, to an affiliate of Occidental Petroleum Corporation, and to Mr. O Malley, our chairman of the board and chief executive officer, or other executive officers designated by Mr. O Malley who agree to participate, at a price per share equal to the public offering price in this offering, less the underwriting discount and commission per share. Any shares sold in the private equity commitment will be sold without registration under the securities laws. Unless we indicate otherwise, the information in this prospectus does not give effect to the sale of any shares of common stock in the private equity commitment.

Risks Relating to Our Business

As part of your evaluation of our company, you should take into account the risks we face in our business and not solely our outlook for the refining industry, our competitive strengths or our business strategies. For example, our position as a pure-play refiner exposes us to volatility in refining industry margins; our long-term heavy sour crude oil supply agreement renders us highly dependent upon that supply, which could be interrupted by events beyond the control of us or the supplier; and our strategy of growing through acquisitions and by undertaking discretionary capital projects involves many factors beyond our control. See Risk Factors for a more detailed discussion of factors you should carefully consider before deciding to invest in shares of our common stock.

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Fourth Quarter and Year-end Results (Unaudited)

The following table is a summary of our unaudited financial results for the quarter and year ended December 31, 2002 as compared to the same periods in 2001:

	Three months ended December 31,		Year ended December 31,	
	2001	2002	2001	2002
	(in millions, except per share data, unaudited)			
Financial Results				
Income (loss) from continuing operations before income taxes and minority interest	$ (58.4)	$ 53.3	$ 236.2	$ (210.1)
Income tax benefit (provision)	26.3	(18.6)	(52.4)	81.3
Minority interest	(0.4)		(12.8)	1.7
Income (loss) from continuing operations	(32.5)	34.7	171.0	(127.1)
Discontinued operations, net of tax benefit	(9.5)		(18.0)	
Preferred stock dividends	(2.5)		(10.4)	(2.5)
Net income (loss) available to common stockholders	$ (44.5)	$ 34.7	$ 142.6	$ (129.6)
Net income (loss) per common share (fully diluted):				
Income (loss) from continuing operations	$ (1.10)	$ 0.60	$ 4.65	$ (2.65)
Discontinued operations	(0.30)		(0.52)	
Net income (loss)	$ (1.40)	$ 0.60	$ 4.13	$ (2.65)
Weighted average common shares outstanding (in millions)	31.8	58.1	34.5	49.0
Selected Operational Data				
Crude oil throughput (in thousands of barrels per day)	443.3	354.9	439.7	412.8
Per barrel of throughput (in dollars):				
Gross margin	$ 3.16	$ 6.33	$ 7.27	$ 4.45
Operating expenses	2.74	2.88	2.91	2.87
Market Indicators				
(dollars per barrel, except as noted)				
West Texas Intermediate (WTI) crude oil	$ 20.32	$ 28.30	$ 25.96	$ 26.13
Crack Spreads:				
Gulf Coast 3/2/1	1.94	3.72	4.22	3.13
Gulf Coast 2/1/1	2.08	3.61	3.92	2.72
Chicago 3/2/1	4.49	6.24	7.90	5.00
Crude Oil Differentials:				
WTI less WTS (sour)	1.91	1.72	2.81	1.38
WTI less Maya (heavy sour)	6.33	6.14	8.76	5.21
WTI less Dated Brent (foreign)	0.87	1.46	1.48	1.12
Natural Gas (per million btus)	2.17	3.92	4.22	3.17

Our net income (loss) available to common stockholders improved from a loss of $44.5 million, or $1.40 per share, for the fourth quarter ended December 31, 2001 to income of $34.7 million, or $.60 per share, for the 2002 fourth quarter. This improvement was due primarily to improved crack spreads in both the Gulf Coast and Chicago markets, partially offset by lower crude oil throughput rates as a result of refinery disruptions due to hurricanes, scheduled and unscheduled maintenance, and the closure of our Hartford, Illinois refinery at the

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beginning of the quarter. Additionally, our earnings improved as a result of reductions in non-energy related operating expenses and our general and administrative expenses, and a decline in our interest expense due to the application of proceeds from our initial public offering to retire long-term debt.

Net income (loss) available to common stockholders for the year ended December 31, 2002 was a loss of $129.6 million, or $2.65 per share, compared to earnings of $142.6 million, or $4.13 per share, for the year ended December 31, 2001. Our operating results declined from the prior year due primarily to a decline in crack spreads and a substantial narrowing of the heavy sour crude oil differential. Our pretax results included restructuring and other charges totaling $172.9 million and $176.2 million for the years ended December 31, 2002 and 2001, respectively. For 2002, these charges included $137.4 million related to the closure of the Hartford refinery, $27.4 million primarily for severance and other charges related to the restructuring of our Port Arthur, Texas and Lima, Ohio refineries and our St. Louis general and administrative operations, $2.5 million related to the restructuring of two of our subsidiaries, $1.4 million for idled equipment, and $4.2 million related to the write-off of an equity investment. For 2001, restructuring charges included $167.2 million for the closure of our Blue Island, Illinois refinery and $9.0 million for idled equipment.

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Our principal executive offices are located at 1700 E. Putnam Avenue, Suite 500, Old Greenwich, CT 06870 and our telephone number is (203) 698-7500.

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THE OFFERING

Common stock offered	11,500,000 shares
Common stock to be outstanding after this offering	69,543,935 shares
Over-allotment option	1,725,000 shares
Use of proceeds	We expect to receive net proceeds from the sale of shares of our common stock in this offering of approximately $239.0 million, or $275.0 million if the underwriters exercise their over-allotment option in full. We intend to use the net proceeds from this offering and the other financing transactions to finance the Memphis refinery acquisition and to refinance certain indebtedness of our subsidiaries.
Dividend policy	We do not expect to pay dividends on our shares of common stock for the foreseeable future.
New York Stock Exchange symbol	PCO

The number of shares of common stock to be outstanding after this offering is based on 58,043,935 shares outstanding as of December 31, 2002 and, unless we indicate otherwise, excludes:

- 4,589,480 shares issuable upon the exercise of stock options held by our directors, employees and former employees which were outstanding as of December 31, 2002, with exercise prices ranging from $9.90 to $24.95 per share;
- an additional 1,967,575 shares authorized and reserved for issuance to our directors or employees under our stock incentive plans and other agreements; and
- shares that the underwriters have the option to purchase from us solely to cover over-allotments.

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SUMMARY FINANCIAL DATA

The following table presents summary financial and other data about us. The summary statement of earnings and cash flow data for the years ended December 31, 1999, 2000 and 2001 are derived from our audited consolidated financial statements, including the notes thereto, appearing elsewhere in this prospectus. The summary statement of earnings and cash flow data for the nine months ended September 30, 2001 and 2002, and the balance sheet data as of September 30, 2002, are derived from our unaudited condensed consolidated financial statements, including the notes thereto, appearing elsewhere in this prospectus. The interim information was prepared on a basis consistent with that used in preparing our audited financial statements with only such recurring adjustments as are necessary, in management s opinion, for a fair statement of the results for the periods presented. The as adjusted balance sheet data give effect to this offering, the debt financing and the use of proceeds as if each had occurred on September 30, 2002. This table should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and our financial statements, including the notes thereto, appearing elsewhere in this prospectus.

	Year Ended December 31,			Nine Months Ended September 30,	
	1999	2000	2001	2001	2002
	(in millions, except per share data)				
Statement of earnings data:					
Net sales and operating revenues	$ 4,520.5	$ 7,301.7	$ 6,417.5	$ 5,170.9	$ 4,807.1
Cost of sales	4,099.8	6,562.5	5,251.4	4,133.7	4,342.8
Gross margin	420.7	739.2	1,166.1	1,037.2	464.3
Operating expenses(1)	402.8	467.7	467.7	355.8	338.2
General and administrative expenses(1)	51.5	53.0	63.3	45.3	40.8
Stock option compensation expense					9.9
Depreciation and amortization(2)	63.1	71.8	91.9	67.7	64.9
Inventory recovery from market write-down	(105.8)				
Refinery restructuring and other charges			176.2	176.2	172.9
Operating income (loss)	9.1	146.7	367.0	392.2	(162.4)
Interest expense and finance income, net(3)	(91.5)	(82.2)	(139.5)	(106.3)	(81.5)
Gain (loss) on extinguishment of long-term debt(4)			8.7	8.7	(19.5)
Income tax (provision) benefit	12.0	25.8	(52.4)	(78.7)	99.9
Minority interest in subsidiary	1.4	(0.6)	(12.8)	(12.4)	1.7
Income (loss) from continuing operations	(69.0)	89.7	171.0	203.5	(161.8)
Discontinued operations, net of taxes(5)	32.6		(18.0)	(8.5)	
Net income (loss)	(36.4)	89.7	153.0	195.0	(161.8)
Preferred stock dividends	(8.6)	(9.6)	(10.4)	(7.9)	(2.5)
Net income (loss) available to common stockholders	$ (45.0)	$ 80.1	$ 142.6	$ 187.1	$ (164.3)
Income (loss) from continuing operations per share:					
basic	$ (3.59)	$ 2.79	$ 5.05	$ 6.15	$ (3.57)
diluted	(3.59)	2.55	4.65	5.67	(3.57)
Weighted average number of common shares outstanding:					
basic	21.6	28.8	31.8	31.8	46.0
diluted	21.6	31.5	34.5	34.5	46.0

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	Year Ended December 31,			Nine Months Ended September 30,	
	1999	2000	2001	2001	2002
	(in millions, except as noted)				
Cash flow data:					
Cash flow from operating activities	$ 85.5	$ 124.4	$ 439.2	$ 390.2	$ (42.2)
Cash flow from investing activities	(321.3)	(375.3)	(152.9)	(98.5)	(91.8)
Cash flow from financing activities	393.9	234.8	(66.3)	(68.8)	(219.8)
EBITDA(6)	72.2	218.5	458.9	459.9	(97.5)
Adjusted EBITDA(7)	(33.6)	218.5	635.1	636.1	75.4
Capital expenditures for property, plant and equipment	438.2	390.7	94.5	57.8	64.1
Capital expenditures for turnarounds	77.9	31.5	49.2	41.3	33.4
Key operating statistics:					
Production (barrels per day in thousands)	460.5	477.3	463.4	459.6	454.8
Crude oil throughput (barrels per day in thousands)	451.7	468.0	439.7	438.8	432.4
Per barrel of crude oil throughput:					
Gross margin	$ 2.55	$ 4.32	$ 7.27	$ 8.66	$ 3.93
Operating expenses	2.44	2.73	2.91	2.97	2.87

	As of September 30, 2002	
	Actual	As Adjusted
	(in millions)	
Balance sheet data:		
Cash, cash equivalents and short-term investments(8)	$ 209.9	$ 226.5
Working capital	291.7	308.3
Total assets	2,292.5	2,649.1
Total debt	925.3	1,045.2
Stockholders equity	658.6	895.4

(1) Certain reclassifications have been made to prior period amounts to conform them to current period presentation.

(2) Amortization includes amortization of turnaround costs. However, this may not be permitted under generally accepted accounting principles, or GAAP, in future periods. See Management s Discussion and Analysis of Financial Condition and Results of Operations Accounting Standards Critical Accounting Standards.

(3) Interest expense and finance income, net, includes amortization of debt issuance costs of $7.9 million, $12.4 million, $14.9 million, $10.9 million and $9.5 million for the years ended December 31, 1999, 2000 and 2001, and for the nine months ended September 30, 2001 and 2002, respectively. Interest expense and finance income, net, also includes interest on all indebtedness, net of capitalized interest and interest income.

(4) In the second quarter of 2002, we elected the early adoption of SFAS No. 145 and, accordingly, have included the gain (loss) on extinguishment of long-term debt in Income from continuing operations as opposed to as an extraordinary item, net of taxes, below Income from continuing operations in our statement of operations. We have accordingly restated our statement of operations and statement of cash flow for 2001.

(5) Discontinued operations is net of an income tax provision of $21.0 million in 1999, and income tax benefits of $11.5 million and $8.5 million in 2001 and for the nine months ended September 30, 2001, respectively.

(6) Earnings before interest, taxes, depreciation and amortization, or EBITDA, is a commonly used non-GAAP financial measure but should not be construed as an alternative to operating income or net income as an indicator of our performance, nor as an alternative to cash flow from operating activities, investing activities

or financing activities as a measure of liquidity, in each case as such measures are determined in accordance with GAAP. EBITDA is presented because we believe that it is a useful indicator of a company s ability to incur and service debt. EBITDA, as we calculate it, may not be comparable to similarly-titled measures reported by other companies.

(7) Adjusted EBITDA represents EBITDA excluding refinery restructuring and other charges of $176.2 million in 2001, $176.2 million in the nine months ended September 30, 2001, and $172.9 million in the nine months ended September 30, 2002, and an inventory recovery from market write-down of $105.8 million in 1999. The $176.2 million charge in the full year of 2001 and in the nine months ended September 30, 2001 included $167.2 million related to the closure of our Blue Island refinery. For the nine months ended September 30, 2002, the charge of $172.9 million included $137.4 million related to the closure of the Hartford refinery. Adjusted EBITDA is presented because we believe it is a useful indicator to our investors of our ability to incur and service debt based on our ongoing operations. Adjusted EBITDA should not be considered by investors as an alternative to operating income or net income as an indicator of our performance, nor as an alternative to cash flow from operating activities, investing activities or financing activities as a measure of liquidity. Because all companies do not calculate EBITDA identically, this presentation of adjusted EBITDA may not be comparable to EBITDA, adjusted EBITDA or other similarly-titled measures of other companies.

(8) Cash, cash equivalents and short-term investments includes $51.9 million of cash and cash equivalents restricted for debt service as of September 30, 2002.

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RISK FACTORS

An investment in our common stock involves risk. You should consider carefully, in addition to the other information contained in this prospectus, the following risk factors before deciding to purchase any common stock.

Risks Related to our Business and our Industry

Volatile margins in the refining industry may negatively affect our future operating results and decrease our cash flow.

Our financial results are primarily affected by the relationship, or margin, between refined product prices and the prices for crude oil and other feedstocks. The cost to acquire our feedstocks and the price at which we can ultimately sell refined products depend upon a variety of factors beyond our control. Historically, refining margins have been volatile, and they are likely to continue to be volatile in the future. Future volatility may negatively affect our results of operations, since the margin between refined product prices and feedstock prices may decrease below the amount needed for us to generate net cash flow sufficient for our needs.

Specific factors, in no particular order, that may affect our refining margins include:

- accidents, interruptions in transportation, inclement weather or other events that cause unscheduled shutdowns or otherwise adversely affect our plants, machinery, pipelines or equipment, or those of our suppliers or customers;
- changes in the cost or availability to us of transportation for feedstocks and refined products;
- failure to successfully implement our planned capital projects or to realize the benefits expected for those projects;
- changes in fuel specifications required by environmental and other laws, particularly with respect to oxygenates and sulfur content;
- rulings, judgments or settlements in litigation or other legal matters, including unexpected environmental remediation or compliance costs at our facilities in excess of any reserves, and claims of product liability or personal injury; and
- aggregate refinery capacity in our industry to convert heavy sour crude oil into refined products.

Other factors that may affect our margins, as well as the margins in our industry in general, include, in no particular order:

- domestic and worldwide refinery overcapacity or undercapacity;
- aggregate demand for crude oil and refined products, which is influenced by factors such as weather patterns, including seasonal fluctuations, and demand for specific products such as jet fuel, which may themselves be influenced by acts of God, nature and acts of terrorism;
- domestic and foreign supplies of crude oil and other feedstocks and domestic supply of refined products, including from imports;
- the ability of the members of the Organization of Petroleum Exporting Countries, or OPEC, to maintain oil price and production controls;
- political conditions in oil producing regions, including the Middle East, Africa and Latin America;
- refining industry utilization rates;
- pricing and other actions taken by competitors that impact the market;

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- price, availability and acceptance of alternative fuels;
- adoption of or modifications to federal, state or foreign environmental, taxation and other laws and regulations;
- price fluctuations in natural gas and electricity; and
- general economic conditions.

A significant interruption or casualty loss at either of our refineries could reduce our production, particularly if not fully covered by our insurance.

Our business currently consists of owning and operating two refineries. As a result, our operations could be subject to significant interruption if either of our refineries were to experience a major accident, be damaged by severe weather or other natural disaster, or otherwise be forced to shut down. Any such shutdown would reduce the production from that refinery. For example, in late September 2002 and early October 2002, two hurricanes, both of which had paths that brought them through the Gulf Coast region of the United States, caused crude oil delivery delays and the shutdown of various plants and businesses in the region. These hurricanes caused delays in crude oil deliveries to both of our refineries and forced a complete shutdown of the operating units at our Port Arthur refinery for approximately four days. It took several additional days to return all of the Port Arthur units to normal processing amounts. Following the startup of the Port Arthur refinery units, we discovered problems with our reformer unit that we believe were caused by the shutdown and subsequent restart. As a result, we experienced additional crude oil processing limitations and reduced production for approximately two weeks while the reformer unit was repaired. There is also risk of mechanical failure and equipment shutdowns. Further, in such situations, undamaged refinery processing units may be dependent on or interact with damaged sections of our refineries and, accordingly, are also subject to being shut down. For example, in February 2002, we shut down the coker unit at our Port Arthur refinery for ten days for unplanned maintenance and, as a result of the shutdown, we reduced crude throughput to some of the downstream units for that ten-day period. In the event any of our refineries is forced to shut down for a significant period of time, it would have a material adverse effect on our earnings, our other results of operations and our financial condition as a whole. Furthermore, if any of the above events were not fully covered by our insurance, it could have a material adverse effect on our earnings, our other results of operations and our financial condition.

Disruption of our ability to obtain crude oil could reduce our margins and our other results of operations.

Although we have one long-term crude oil supply contract, the majority of our crude oil supply is acquired under short-term contractual arrangements or in the spot market. Our short-term crude oil supply contracts are terminable on one to three months notice. Further, a significant portion of our feedstock requirements is supplied from Latin America, Africa and the Middle East (including Iraq), and we are subject to the political, geographic and economic risks attendant to doing business with suppliers located in those regions. For example, on April 8, 2002, Iraq announced that it was halting all oil exports for a 30-day period. In the event that one or more of our supply contracts is terminated, we may not be able to find alternative sources of supply. If we are unable to obtain adequate crude oil volumes or are only able to obtain such volumes at unfavorable prices, our margins and our other results of operations could be materially adversely affected.

Our Port Arthur refinery is highly dependent upon a PEMEX affiliate for its supply of heavy sour crude oil, which could be interrupted by events beyond the control of PEMEX.

For the nine months ended September 30, 2002, we sourced approximately 83% of our Port Arthur refinery s crude oil from P.M.I. Comercio Internacional, S.A. de C.V., or PMI, an affiliate of PEMEX. Therefore, a large proportion of our crude oil needs is influenced by the adequacy of PEMEX s crude oil reserves, the estimates of which are not precise and are subject to revision at any time. In the event that PEMEX s affiliate were to terminate our crude oil supply agreement or default on its supply obligations, we

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would need to obtain heavy sour crude oil from another supplier and would lose the potential benefits of the coker gross margin support mechanism contained in the supply agreement. Alternative supplies of crude oil may not be available or may not be on terms as favorable as those negotiated with PEMEX s affiliate. In addition, the processing of oil supplied by a third party may require changes to the configuration of our Port Arthur refinery, which could require significant unbudgeted capital expenditures.

Furthermore, the obligation of PEMEX s affiliate to deliver heavy sour crude oil under the agreement may be delayed or excused by the occurrence of conditions and events beyond the reasonable control of PEMEX, such as:

- extreme weather-related conditions;
- production or operational difficulties and blockades;
- embargoes or interruptions, declines or shortages of supply available for export from Mexico, including shortages due to increased domestic demand and other national or international political events; and
- certain laws, changes in laws, decrees, directives or actions of the government of Mexico.

The government of Mexico may direct a reduction in our supply of crude oil, so long as that action is taken in common with proportionately equal supply reductions under its long-term crude oil supply agreements with other parties and the amount by which it reduces the quantity of crude oil to be sold to us shall first be applied to reduce quantities of crude oil scheduled for sale and delivery to our Port Arthur refinery under any other crude oil supply agreement with us or any of our affiliates. Mexico is not a member of OPEC, but in 1998 it agreed with the governments of Saudi Arabia and Venezuela to reduce Mexico s exports of crude oil by 200,000 bpd. In March 1999, Mexico further agreed to cut exports of crude oil by an additional 125,000 bpd. As a consequence, during 1999, PEMEX reduced its supply of oil under some oil supply contracts by invoking an excuse clause based on governmental action similar to one contained in our long-term crude oil supply agreement. It is possible that PEMEX could reduce our supply of crude oil by similarly invoking the excuse provisions in the future.

Competitors who produce their own supply of feedstocks, have extensive retail outlets, make alternative fuels or have greater financial resources than we do may have a competitive advantage over us.

The refining industry is highly competitive with respect to both feedstock supply and refined product markets. We compete with numerous other companies for available supplies of crude oil and other feedstocks and for outlets for our refined products. We are not engaged in the petroleum exploration and production business and therefore do not produce any of our crude oil feedstocks. We do not have a retail business and therefore are dependent upon others for outlets for our refined products. Many of our competitors, however, obtain a significant portion of their feedstocks from company-owned production and have extensive retail outlets. Competitors that have their own production or extensive retail outlets, with brand-name recognition, are at times able to offset losses from refining operations with profits from producing or retailing operations, and may be better positioned to withstand periods of depressed refining margins or feedstock shortages. A number of our competitors also have materially greater financial and other resources than we possess. These competitors have a greater ability to bear the economic risks inherent in all phases of the refining industry. In addition, we compete with other industries that provide alternative means to satisfy the energy and fuel requirements of our industrial, commercial and individual consumers. If we are unable to compete effectively with these competitors, both within and outside of our industry, our financial condition and results of operations, as well as our business prospects, could be materially adversely affected.

Our substantial indebtedness may limit our financial flexibility.

Our substantial indebtedness has significantly affected our financial flexibility historically and may significantly affect our financial flexibility in the future. As of September 30, 2002, after giving effect to this offering and the debt financing and the use of a portion of these proceeds to refinance certain indebtedness of our subsidiaries, we would have had total consolidated debt, including current maturities, of $1,045.2 million and cash, short-term investments and cash restricted for debt service of $226.5 million. On the same basis, we would have had stockholders equity of $895.4 million and a total debt to total capitalization ratio of 53.9% as of September 30, 2002. In addition to the debt financings, we or our subsidiaries may incur additional indebtedness in the future, although our ability to do so will be restricted by the terms of our existing indebtedness. In addition to the Memphis refinery acquisition, we are currently evaluating several refinery acquisitions, some of which may be significant. Any future acquisition could also require us to incur additional indebtedness in order to finance all or a portion of such acquisition. The level of our indebtedness has several important consequences for our future operations, including that:

- a significant portion of our cash flow from operations will be dedicated to the payment of principal of, and interest on, our indebtedness and will not be available for other purposes;
- covenants contained in our existing debt arrangements require us to meet or maintain certain financial tests, which may affect our flexibility in planning for, and reacting to, changes in our industry, such as being able to take advantage of acquisition opportunities when they arise;
- our ability to obtain additional financing for working capital, capital expenditures, acquisitions, general corporate and other purposes may be limited;
- we may be at a competitive disadvantage to those of our competitors that are less leveraged; and
- we may be more vulnerable to adverse economic and industry conditions.

Restrictive covenants in our subsidiaries debt instruments limit our ability to move funds and assets among our subsidiaries and may limit our ability to undertake certain types of transactions.

Various covenants in our subsidiaries debt instruments and other financing arrangements may restrict our and our subsidiaries financial flexibility in a number of ways. Our indebtedness subjects our subsidiaries to significant financial and other restrictive covenants, including restrictions on their ability to incur additional indebtedness, place liens upon assets, pay dividends or make certain other restricted payments and investments, consummate certain asset sales or asset swaps, enter into certain transactions with affiliates, make certain payments to us, enter into sale and leaseback transactions, conduct businesses other than their current businesses, merge or consolidate with any other person or sell, assign, transfer, lease, convey or otherwise dispose of all or substantially all of their assets. Some of our subsidiaries debt instruments also require them to satisfy or maintain certain financial condition tests. Our subsidiaries ability to meet these financial condition tests can be affected by events beyond our control and they may not meet such tests.

We have significant principal payments under our indebtedness coming due in the next several years; we may be unable to repay or refinance such indebtedness.

We have significant principal payments due under our debt instruments. After giving effect to this offering and the debt financing and the use of a portion of these proceeds to refinance certain indebtedness of our subsidiaries, we will be required to make the following principal payments on our long-term debt: $14.9 million in 2003; $25.6 million in 2004; $38.5 million in 2005; $46.4 million in 2006; $318.4 million in 2007; and $601.9 million in the aggregate thereafter. In addition to the Memphis refinery acquisition, we are currently evaluating several refinery acquisitions, some of which may be significant. Any future acquisition could also require us to incur additional indebtedness in order to finance all or a portion of such acquisition, and therefore may increase our principal payments coming due in the next several years.

Our ability to meet our principal obligations will be dependent upon our future performance, which in turn will be subject to general economic conditions, industry cycles and financial, business and other factors affecting our operations, many of which are beyond our control. Our business may not continue to generate sufficient cash flow from operations to repay our substantial indebtedness. If we are unable to generate sufficient cash flow from operations, we may be required to sell assets, to refinance all or a portion of our indebtedness or to obtain additional financing. Refinancing may not be possible and additional financing may not be available on commercially acceptable terms, or at all.

Compliance with, and changes in, environmental laws could adversely affect our results of operations and our financial condition.

We are subject to extensive federal, state and local environmental laws and regulations, including those relating to the discharge of materials into the environment, waste management, pollution prevention, remediation of contaminated sites and the characteristics and composition of gasoline and diesel fuels. In addition, some of these laws and regulations require our facilities to operate under permits that are subject to renewal or modification. These laws and regulations and permits can often require expensive pollution control equipment or operational changes to limit impacts or potential impacts on the environment and/or health and safety. A violation of these laws and regulations or permit conditions can result in substantial fines, criminal sanctions, permit revocations and/or facility shutdowns. Compliance with environmental laws and regulations significantly contributes to our operating costs. In addition, we have made and expect to make substantial capital expenditures on an ongoing basis to comply with environmental laws and regulations.

In addition, new laws, new interpretations of existing laws, increased governmental enforcement of environmental laws or other developments could require us to make additional unforeseen expenditures. These expenditures or costs for environmental compliance could have a material adverse effect on our financial condition, results of operations and cash flow. See Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Cash Flow from Investing Activities. For example, the United States Environmental Protection Agency, or EPA, has promulgated regulations under the federal Clean Air Act that establish stringent sulfur content specifications for gasoline and low-sulfur highway, or on-road , diesel fuel designed to reduce air emissions from the use of these products.

In February 2000, the EPA promulgated the Tier 2 Motor Vehicle Emission Standards Final Rule for all passenger vehicles mandating that the average sulfur content of gasoline for highway use produced at any refinery not exceed 30 parts per million, or ppm, during any calendar year by January 1, 2006 with a phase in of these requirements beginning on January 1, 2004. We currently expect to produce gasoline under the new sulfur standards at the Port Arthur refinery prior to January 1, 2004 and, as a result of the corporate pool averaging provisions of the regulations, will not be required to meet the new sulfur standards at the Lima refinery until July 1, 2004, a six month deferral. A further delay in the requirement to meet the new sulfur standards at the Lima refinery through 2005 may be possible through the purchase of sulfur allotments and credits which arise from a refiner producing gasoline with a sulfur content below specified levels prior to the end of 2005, the end of the phase-in period. There can be no assurances that sufficient allotments or credits to defer investment at the Lima refinery will be available, or if available, at what cost. We believe, based on current estimates and on a January 1, 2004 compliance date for both the Port Arthur and Lima refineries, that compliance with the new Tier 2 gasoline specifications will require capital expenditures for the Lima and Port Arthur refineries in the aggregate through 2005 of approximately $255 million. More than 95% of the total investment to meet the Tier 2 gasoline specifications is expected to be incurred during 2002 through 2004, with the greatest concentration of spending occurring in 2003.

In January 2001, the EPA promulgated its on-road diesel regulations, which will require a 97% reduction in the sulfur content of diesel fuel sold for highway use by June 1, 2006, with full compliance by January 1, 2010. We estimate capital expenditures in the aggregate through 2006 required to comply with the diesel standards at our Port Arthur and Lima refineries of approximately $245 million. More than 95% of the projected investment is expected to be incurred during 2004 through 2006 with the greatest concentration of spending occurring in 2005. Since the Lima refinery does not currently produce diesel fuel to on-road specifications, we are considering an acceleration of the low-sulfur diesel investment at the Lima refinery in order to capture this incremental product value. If the investment is accelerated, production of the low-sulfur fuel may begin by the first quarter of 2005. Regulations regarding the sulfur content of off-road diesel are pending. See Business Environmental Matters Environmental Compliance Fuel Regulations.

In addition, on April 11, 2002, the EPA promulgated regulations to implement Phase II of the petroleum refinery Maximum Achievable Control Technology rule under the federal Clean Air Act, referred to as MACT II, which regulates emissions of hazardous air pollutants from certain refinery units. Based on currently available information, we expect to spend approximately $45 million over the next three years, with the greatest concentration of spending evenly spread out over 2003 and 2004.

Based on currently available information, we expect our acquisition of the Memphis refinery to increase our costs of complying with Tier 2 gasoline standards and low sulfur diesel standards by approximately $80 million and $100 million, respectively. The estimated $80 million in spending for Tier 2 gasoline compliance would be incurred during 2003 and 2004. The estimated $100 million in spending for low sulfur diesel compliance would be incurred between 2004 and 2006, with the greatest concentration of spending in 2005. No capital expenditures are expected to be required for MACT II compliance at the Memphis refinery. Any future acquisition could require us to make significant capital expenditures to comply with environmental laws and regulations. There can be no assurances that our internally generated cash flow will be sufficient to support each of the foregoing capital expenditures at all of the facilities.

Environmental clean-up and remediation costs of our sites and environmental litigation could decrease our cash flow, reduce our results of operations and impair our financial condition.

We are subject to liability for the investigation and clean-up of environmental contamination at each of the properties that we own or operate, at certain properties we formerly owned or operated and at off-site locations where we arranged for the disposal of hazardous substances. We are involved in several proceedings or other projects relating to our liability for the investigation and clean-up of such sites. We may become involved in further litigation or other proceedings. If we were to be held responsible for damages in any existing or future litigation or proceedings, such costs may not be covered by insurance and may be material. For example, there is extensive contamination at our Port Arthur refinery site and contamination at our Lima refinery site. Chevron Products Company, the former owner of the Port Arthur refinery, has retained environmental remediation obligations regarding pre-closing contamination for all areas of the refinery except those under or within 100 feet of active processing units, and BP has retained liability for certain environmental costs relating to operations of, or associated with, the Lima refinery site prior to our acquisition of that facility. However, if either of these parties fails to satisfy its obligations for any reason, or if significant liabilities arise in the areas in which we assumed liability, we may become responsible for the remediation. If we are forced to assume liability for the cost of this remediation or other remediation relating to our current or former facilities, such liability could have a material adverse effect on our financial condition. As a result, in addition to making capital expenditures or incurring other costs to comply with environmental laws, we also may be liable for significant environmental litigation or remediation costs and other liabilities arising from the ownership or operation of these assets by prior owners, which could materially adversely affect our financial condition, results of operations and cash flow.

In connection with the closure of our Blue Island, Illinois and Hartford, Illinois refineries, we are required to conduct environmental remediation at those facilities. We are currently assessing our remedial obligations at these closed facilities and have an aggregate reserve of $49.6 million as of September 30, 2002. Also, in connection with our sale of certain retail properties and product terminals in 1999, we agreed to indemnify the purchasers for certain environmental conditions arising during our ownership and operation of these assets. Clean-up costs with respect to any of these matters may exceed our estimates, which could, in turn, have a material adverse effect on our financial condition, results of operations and cash flow. In particular, we sold the majority of our former retail properties to Clark Retail Enterprises, Inc., or CRE, which, together with its parent company, Clark Retail Group, has recently filed for Chapter 11 bankruptcy protection. In addition to our obligations under the indemnities, we may be jointly and severally liable for CRE s obligations under leases for these retail locations, including payment of rent and environmental cleanup responsibilities for releases of petroleum occurring during the term of the leases. We may also incur other significant liabilities for environmental obligations at these sites.

We may also face liability arising from current or future claims alleging personal injury or property damage due to exposure to chemicals or other hazardous substances, such as asbestos and benzene, at or from our facilities. We may also face liability for personal injury, property damage, natural resource damage or clean-up costs for the alleged migration of contamination or hazardous substances from our facilities. A significant increase in the number or success of these claims could materially adversely affect our financial condition, results of operations and cash flow. See Business Environmental Matters and Business Legal Proceedings for a description of some of these claims.

We have additional capital needs for which our internally generated cash flow may not be adequate; we may have insufficient liquidity to meet those needs.

In addition to the capital expenditures we will make to comply with Tier 2 gasoline standards, on-road diesel regulations and MACT II regulations, we have additional short-term and long-term capital needs. Our short-term working capital needs are primarily crude oil purchase requirements, which fluctuate with the pricing and sourcing of crude oil. Our internally generated cash flow and availability under our working capital facilities may not be sufficient to meet these needs. We also have significant long-term needs for cash. We estimate that mandatory capital and turnaround expenditures, excluding the non-recurring capital expenditures required to comply with Tier 2 gasoline standards, on-road diesel regulations and MACT II regulations described above, will be approximately $105 million per year from 2003 through 2006. Based on currently available information, we expect that our acquisition of the Memphis refinery will increase this amount to approximately $153 million annually through 2006 and any other significant acquisition could require us to make additional capital expenditures in this regard. Our internally generated cash flow may not be sufficient to support such capital expenditures.

We may not be able to implement successfully our discretionary capital expenditure projects.

We could undertake a number of discretionary capital expenditure projects designed to increase the productivity and profitability of our refineries. Many factors beyond our control may prevent or hinder our undertaking of some or all of these projects, including compliance with or liability under environmental regulations, a downturn in refining margins, technical or mechanical problems, lack of availability of capital and other factors. Failure to successfully implement these profit-enhancing strategies may adversely affect our business prospects and competitive position in the industry.

A substantial portion of our workforce is unionized and we may face labor disruptions that would interfere with our refinery operations.

As of December 1, 2002, we employed 1,413 people, approximately 60% of whom were covered by collective bargaining agreements. The collective bargaining agreement covering employees at our Port Arthur refinery expires in January 2006 and the agreement covering employees at our Lima refinery expires in April 2006. The Memphis refinery employs approximately 320 people, including support personnel. Approximately 50% of those employees are covered by a collective bargaining agreement which expires in January 2006. Our relationships with the relevant unions at our current facilities have been good and we have never experienced a work stoppage as a result of labor disagreements. However, we cannot assure you that this situation will continue. A labor disturbance at any of our refineries could have a material adverse effect on that refinery s operations.

We are controlled by a limited number of stockholders, and in the future there may be conflicts of interest between these stockholders and our other stockholders, who will have less ability to influence our business.

After this offering and assuming no shares are sold pursuant to the private equity commitment, Blackstone will beneficially own 40.0% of our common stock, or 39.0% if the underwriters exercise their over-allotment

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option in full, and Occidental will own 11.1% of our common stock, or 10.8% if the underwriters exercise their over-allotment option in full. As a result, each of these stockholders, individually or in conjunction with other stockholders, may be able to control the election of our directors and determine our corporate policies and business strategy, including the approval of potential mergers or acquisitions, asset sales and other significant corporate transactions. Each of these stockholders interests may not coincide with the interests of the other holders of our common stock.

We have not fully developed or implemented a disaster recovery plan for our information systems, which could adversely affect business operations should a major physical disaster occur.

We are dependent upon functioning information systems to conduct our business. A system failure or malfunction may result in an inability to process transactions or lead to a disruption of operations. Although we regularly backup our programs and data, we do not currently have a comprehensive disaster recovery plan providing a hot site facility for immediate system recovery should a major physical disaster occur at our general office, our executive office or at one of our refineries. A comprehensive disaster recovery plan is currently being developed, with completion targeted in 2003.

Our federal income tax carryforward attributes could be substantially limited if we experience an ownership change as defined in the Internal Revenue Code.

We had consolidated federal income tax net operating loss carryforwards of approximately $245.9 million at December 31, 2001, and have incurred an additional net operating loss during the nine months ended September 30, 2002. Our net operating loss carryforwards will begin to terminate with the year ending December 31, 2012, to the extent they have not been used to reduce taxable income prior to such time. Our ability to use our net operating loss carryforwards to reduce taxable income and to utilize other losses and certain tax credits is dependent upon, among other things, our not experiencing an ownership change of more than 50% during any three-year testing period as defined in the Internal Revenue Code. We have had significant changes in the ownership of our common stock in the three-year testing period immediately prior to this offering. We expect that as a result of this offering we will be very close to experiencing an ownership change of more than 50%. Accordingly, future changes, even slight changes, in the ownership of our common stock (including, among other things, the exercise of compensatory options) could result in an aggregate change in ownership of more than 50% as defined in the Internal Revenue Code, which could substantially limit the availability of our net operating loss carryforwards, other losses and tax credits.

Risks Related to the Memphis Refinery Acquisition and Future Acquisitions

We may not realize the anticipated benefits of the Memphis refinery acquisition.

Our estimates regarding the earnings, operating cash flow, capital expenditures and liabilities resulting from our acquisition of the Memphis refinery may prove to be incorrect. In addition, we may not realize the anticipated synergies and we may not be successful in integrating the acquired assets into our existing business.

If we do not consummate the Memphis refinery acquisition, we will not realize the anticipated benefits from the acquisition.

Although the information in this prospectus assumes the consummation of the Memphis refinery acquisition, the consummation is subject to the satisfaction of certain conditions precedent, and may be terminated by Williams if the acquisition has not been completed by March 31, 2003. Our failure to acquire the Memphis refinery and related supply and distribution assets from Williams would result in our asset base being smaller than what has been described in this prospectus. Accordingly, we would not realize the anticipated benefits we discuss in this prospectus which are based on our completion of this acquisition. Additionally, if the Memphis refinery acquisition is not consummated for any reason, we would retain broad discretion as to the use of the net proceeds of this offering and the debt financing and may not be able to effectively deploy them.

We may be liable for significant environmental costs relating to the Memphis refinery acquisition or future acquisitions.

The Memphis refinery acquisition agreement provides that the sellers will indemnify us for certain unknown and undisclosed environmental liabilities. The maximum potential amount we can recover for environmental liabilities is limited to $50 million from the sellers under the indemnity plus $50 million under an insurance policy. We are responsible for all other environmental liabilities, including various pending cleanup and compliance matters that we estimate will cost between $9 million and $16 million. Accordingly, we may be responsible for significant environmental related liabilities and costs relating to the acquisition of the Memphis refinery and the related assets. See Compliance with, and changes in, environmental laws could adversely affect our results of operations and our financial condition for a description of capital expenditures we expect to incur with respect to the Memphis refinery. There can be no assurances that these environmental liabilities and/or costs or expenditures to comply with environmental laws will not have a material adverse effect on our financial condition, results of operations and cash flow.

We may not be able to consummate future acquisitions or successfully integrate the Memphis refinery or other future acquisitions into our business.

A substantial portion of our growth over the last several years has been attributed to acquisitions. A principal component of our strategy going forward is to continue to selectively acquire refining assets in order to increase cash flow and earnings. Our ability to do so will be dependent upon a number of factors, including our ability to identify acceptable acquisition candidates, consummate acquisitions on favorable terms, successfully integrate acquired businesses and obtain financing to support our growth and many other factors beyond our control. We may not be successful in implementing our acquisition strategy and, even if implemented, such strategy may not improve our operating results. In addition, the financing of future acquisitions may require us to incur additional indebtedness, which could limit our financial flexibility, or to issue additional equity, which could result in further dilution of the ownership interest of existing shareholders.

In connection with the Memphis refinery acquisition or with future acquisitions, we may experience unforeseen operating difficulties as we integrate the acquired assets into our existing operations. These difficulties may require significant management attention and financial resources that would otherwise be available for the ongoing development or expansion of existing operations. The Memphis refinery acquisition and any future acquisitions involve risks, including:

- unexpected losses of key employees, customers and suppliers of the acquired operations;
- difficulties in integrating the financial, technological and management standards, processes, procedures and controls of the acquired business with those of our existing operations;
- challenges in managing the increased scope, geographic diversity and complexity of our operations; and
- mitigating contingent liabilities.

Risks Related to this Offering

Our stock price may be volatile.

The market price of our common stock has been in the past, and could be in the future, subject to significant fluctuations in response to factors such as those listed in Risks Related to our Business and our Industry Volatile margins in the refining industry may negatively affect our future operating results and decrease our cash flow, and the following, some of which are beyond our control:

- fluctuations in the market prices of crude oil, other feedstocks and refined products, which are beyond our control and may be volatile, such as announcements by OPEC members that they may reduce crude oil output in order to increase prices;

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quarterly variations in our operating results such as those related to the summer and winter driving seasons and resulting demand for unleaded gasoline and heating oil;

operating results that vary from the expectations of securities analysts and investors;

operating results that vary from those of our competitors;

changes in expectations as to our future financial performance, including financial estimates by securities analysts and investors;

announcements by us or our competitors of significant contracts, acquisitions, joint marketing relationships, joint ventures or capital commitments;

announcements by third parties of significant claims or proceedings against us;

future sales of our common stock, for example, when lock-up agreements expire 90 days following this offering; and

general domestic and international economic conditions, particularly following the terrorist attacks of September 2001.

If we or our existing stockholders sell additional shares of our common stock after this offering, the market price of our common stock could decline.

The market price of our common stock could decline as a result of sales of a large number of shares of common stock in the market after this offering, or the perception that such sales could occur. These sales, or the possibility that these sales may occur, also might make it more difficult for us to sell equity securities in the future at a time and at a price that we deem appropriate.

All of the shares we are selling in this offering, plus any shares issued upon the underwriters option to purchase additional common stock, will be freely tradable without restriction under the United States securities laws, unless purchased by our affiliates.

We, our directors and executive officers, Blackstone and Occidental, owning an aggregate of 36,469,406 shares, have agreed not to offer or sell, directly or indirectly, any common stock without the permission of Morgan Stanley & Co. Incorporated for a period of 90 days from the date of this prospectus, subject to certain exceptions. Sales of a substantial number of shares of our common stock following the expiration of these lock-up periods could cause our stock price to fall. In addition, in connection with the Memphis refinery acquisition, under certain circumstances, we may pay up to $100 million of the purchase price through the issuance of our shares instead of cash. These shares of common stock would be valued at the lesser of (1) $15.00 per share less an underwriting discount or (2) $, the net proceeds per share received by us in this offering. See The Acquisition of the Memphis Refinery Overview of the Acquisition. We are also currently evaluating several other refinery acquisitions, some of which may be significant. Any other significant acquisition may require us to issue shares of our common stock or securities linked to shares of our common stock to finance all or a portion of such acquisition. Additionally, we have granted registration rights to certain of our stockholders and, if the sellers receive shares of common stock under the circumstances described above, to the sellers of the Memphis refinery. See Shares Eligible for Future Sale Registration Rights.

In addition, 4,589,480 shares of our common stock are issuable upon the exercise of presently outstanding stock options granted to our directors, employees and former employees under our 1999 Stock Incentive Plan, 2002 Equity Incentive Plan and our 2002 Special Stock Incentive Plan. An additional 1,967,575 shares have been reserved for future issuance under our stock incentive plans and other agreements. We have registered on Form S-8 under the Securities Act all shares of common stock subject to outstanding stock options issuable under our stock incentive plans and shares of certain of our officers and directors. Sales of a substantial number of shares of our common stock following the vesting of these options could cause our stock price to fall.

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Our governing documents and applicable laws include provisions that may discourage a takeover attempt.

Provisions contained in our certificate of incorporation and by-laws and Delaware law could make it difficult for a third party to acquire us, even if doing so might be beneficial to our stockholders. For example, our certificate of incorporation precludes stockholders from taking action by consent, which inhibits stockholders ability to replace board members. Further, only the board of directors or our chairman of the board or chief executive officer may call special meetings of stockholders, which prevents stockholders from calling special meetings to vote on corporate actions. Stockholders who wish to nominate a director or present a matter for consideration at an annual meeting are required to give us notice of such proposal, which gives us time to respond. These provisions could limit the price that certain investors might be willing to pay in the future for shares of our common stock and may have the effect of delaying or preventing a change in control.

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FORWARD-LOOKING STATEMENTS

Some of the matters discussed under the captions Prospectus Summary, Risk Factors, Management s Discussion and Analysis of Financial Condition and Results of Operations, Business and elsewhere in this prospectus include forward-looking statements based on current expectations, estimates, forecasts and projections, beliefs and assumptions made by management. You can identify these forward-looking statements by the use of words like strategy, expects, plans, believes, will, estimates, intends, projects, goals, targets and othe meaning. You can also identify them by the fact that they do not relate strictly to historical or current facts.

Even though we believe our expectations regarding future events are based on reasonable assumptions, forward-looking statements are not guarantees of future performance. Important factors that could cause actual results to differ materially from those contained in our forward-looking statements include those discussed under Risk Factors Risks Related to our Business and our Industry and The Acquisition of the Memphis Refinery Impact of the Acquisition. Because of these uncertainties and others, you should not place undue reliance on our forward-looking statements.

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THE ACQUISITION OF THE MEMPHIS REFINERY

Overview of the Acquisition

On November 25, 2002, we executed an agreement with The Williams Companies and certain of its subsidiaries to purchase their Memphis refinery and related supply and distribution assets located in and around Memphis, Tennessee. The purchase price is $315 million, plus the value of inventories at closing. At current price levels, the value of the inventories is estimated to be $200 million. In addition, the sellers will be entitled to receive from us earn-out payments over the next seven years, up to a maximum of $75 million, based on the excess of a specified average industry refining margin per barrel over a specified margin per barrel, multiplied by a specified throughput volume at the refinery.

The Memphis refinery has a rated crude oil throughput capacity of 190,000 bpd, but typically processes approximately 170,000 bpd. Also included in the acquisition are two truck-loading racks, three petroleum terminals located in the area, pipeline infrastructure that transports both crude oil and refined products, crude oil tankage in Louisiana and an 80 megawatt power plant adjacent to the refinery.

We intend to finance the acquisition with the proceeds from this offering and the other financing transactions. See Use of Proceeds. Additionally, we have received a financing commitment letter from Morgan Stanley Senior Funding, Inc. to provide a portion of the financing to consummate the acquisition, if necessary.

Consummation of the acquisition is conditioned upon us securing the requisite financing. If we are unable to secure this financing, the sellers may elect, under certain circumstances, to receive up to $100 million of the purchase price through the issuance of shares of our common stock instead of cash. These shares would be valued at the lesser of (a) $15.00 per share less an underwriting discount or (b) $, the net proceeds per share received by us in this offering. If we fail to consummate the transaction, we may be obligated to pay the sellers $30 million in cash as liquidated damages. If the sellers elect to receive our common stock under the circumstances described above, they will also have the right, from time to time, to require us to register their stock for resale and to include their shares in future registration statements filed by us.

We also intend to enter into a two-year crude oil supply and product off-take agreement with Morgan Stanley Capital Group Inc., or MSCG, under which MSCG will purchase the Memphis refinery petroleum inventories at closing. Under this agreement, MSCG will (1) lease from us the Memphis refinery tankage, (2) receive, via assignment or sublease, Southcap Capline pipeline storage and historic shipping capacity associated with the Memphis refinery operations, and (3) assign or sub-lease for storage capacity at various product terminals supporting the Memphis refinery operations. Over the term of the agreement, we will purchase crude oil from MSCG delivered into the crude unit and will sell products to MSCG delivered into refinery tankage. Among other things, this transaction will reduce our need to issue standby letters of credit in order to support purchases of crude oil inventory for the Memphis refinery. We intend to enter into a commitment to purchase the petroleum inventories acquired by MSCG upon termination of the agreement with them at then current market prices, as adjusted by certain predetermined contract provisions. There are no assurances that we will enter into this agreement or on these terms.

In the event that the gross proceeds from this offering and the other financing transactions exceed $650 million in the aggregate due to the purchase of shares by the underwriters pursuant to the over-allotment option or otherwise, we may use the additional gross proceeds to pay for the purchase of inventory at closing or fund our investment in accounts receivable that will result as refinery operations commence. Any inventory purchased by us at closing would not be part of the proposed crude oil supply and product offtake agreement with MSCG.

The sellers have agreed, subject to the limitations described below, to indemnify us against all environmental liabilities incurred by us as a result of a breach of their environmental representations and as a result of environmental related matters (1) known by them prior to the closing but not disclosed to us and (2) not known by them prior to the closing. We are responsible for all other environmental liabilities, including various pending cleanup and compliance matters that we estimate will cost between $9 million and $16 million. Any claims made by us against the sellers for environmental liabilities must be made within seven years. The sellers, as a condition to closing, will be required to obtain, at their expense, a ten-year fully pre-paid $50 million environmental insurance policy in support of this obligation covering unknown and undisclosed liabilities for the period of time prior to the acquisition. The maximum amount we can recover for environmental liabilities is limited to $50 million from the sellers plus any amounts provided under the insurance policy. The sellers have also agreed to indemnify us against breaches of their representations and from liabilities arising from the ownership and operation of the assets (other than environmental liabilities) prior to the closing, but the liability of the sellers will be subject to a $5 million deductible and a maximum liability of $50 million.

Completion of the acquisition is also subject to the satisfaction of customary conditions, including regulatory approvals. Pursuant to the requirements of the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, we filed a Notification and Report Form with respect to the Memphis acquisition with the Antitrust Division of the Department of Justice and the Federal Trade Commission on December 10, 2002. As a result, the waiting period applicable to the Memphis refinery acquisition expired at 11:59 p.m., New York City time, on January 9, 2003. The acquisition is expected to close in the first quarter of 2003.

The Memphis Refinery

The Memphis refinery was originally constructed in 1941 and is located on 223 acres along the Mississippi River s Lake McKellar in Memphis, Tennessee. According to the sellers, approximately $400 million has been invested in the refinery over the past four years creating a modern, highly-efficient facility with a 190,000 bpd crude oil throughput capacity. The refinery processes light, sweet crude oil delivered via the Capline pipeline system and distributes its products primarily in the Memphis area and the Mississippi River and lower Ohio River valleys, with occasional market-driven distribution in other markets.

The Memphis refinery s major processing units and associated capacity are listed below:

Unit	Capacity (in barrels per day, except as noted)	Year Built	Most Recent Modification
West crude	80,000	1941	2002
East crude	110,000	1980	1999
Naptha desulfurizer	60,000	1974	2000
Isomerization	4,000	1987	1999
Reformer	36,000	2000	
Distillate desulfurizer	51,000	1980	1993
Fluid catalytic cracking	68,000	1980	1999
Alkylation	12,000	1968	1999
C3/C4 (propane/butane) splitter	8,000	1998	
Sulfur recovery	15-50 tons per day	1982	
Cryogenic unit	300-700	1989	2002
Saturates gas plant	12,000	1996	

We will depreciate these assets in accordance with our policies related to property, plant and equipment, and the assets will have estimated useful lives of approximately 25 to 30 years.

Feedstocks. The Memphis refinery processes predominantly light, sweet crude oil and draws its crude supply (both domestic and foreign) from the Capline pipeline system. It can also receive crude oil via barge. Capline is a 1,140,000 bpd common carrier crude oil pipeline that originates at St. James, Louisiana and terminates at Patoka, Illinois. The refinery is linked to Capline via a 28-mile proprietary pipeline, which connects to Capline near Collierville, Tennessee and has a capacity of 200,000 bpd.

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Product Offtake. The Memphis refinery is the sole supplier of jet fuel to the Memphis International Airport, a major air cargo thoroughfare and a central hub for Federal Express. Federal Express is, and we expect will continue to be, a significant customer of the refinery. The Memphis refinery supplies Federal Express pursuant to a long-term supply agreement which represents approximately 12% of the refinery s total output. In addition to Federal Express, the refinery has a number of supply agreements with terms in excess of one year representing an aggregate of approximately 13% of the refinery s total output. Other than the agreement with Federal Express, no other supply agreement accounts for 10% or more of the refinery s total output.

The refinery s position along the Mississippi River provides a cost advantage in serving numerous upriver markets due to the superior economics of shipping crude oil for refining and subsequent product distribution versus shipping refined products from the Gulf Coast to Memphis. It is also well situated to meet demand for refined products in Nashville, Tennessee, which the Gulf Coast market cannot economically satisfy. The refinery s close proximity to several major electric power plants also provides access to increased distillate demand associated with peaking plants and fuel switching.

Products of the refinery include: premium, mid-grade and regular grades of unleaded gasoline; commercial Jet-A; kerosene; military JP8; diesel; No. 6 fuel oil; propane; refinery grade propylene and sulfur. The Memphis refinery is capable of distributing its products through facilities with nominal capacities as follows: (1) a 120,000 bpd truck-loading rack at the refinery; (2) a 50,000 bpd truck-loading rack at the West Memphis, Arkansas products terminal; (3) a 30,000 bpd jet fuel pipeline to the Memphis International Airport; (4) a 96,000 bpd barge dock at the refinery; (5) a 108,000 bpd barge dock connected to the West Memphis terminal; (6) a two-lane LPG truck-loading rack and (7) a 24-spot LPG rail car-loading rack. Refinery production can also be distributed via barge to markets in Henderson, Owensboro, and Paducah, Kentucky; Nashville, Tennessee; Evansville, Indiana; Cape Girardeau, Missouri; and Greenville, Mississippi.

Energy. The sellers recently completed construction of an 80 megawatt power plant adjacent to the refinery to provide a reliable source of power and to reduce power costs.

Employees. The sellers have indicated that the refinery employs approximately 320 employees, of which approximately one-half is represented by a union. We have agreed to recognize and enter into a contract with the union and intend to offer employment to qualified represented personnel and intend to consider the non-represented employees as candidates for employment.

Impact of the Acquisition

We understand that the sellers historically operated the Memphis refinery as a component of their integrated energy services with a corresponding emphasis on the trading and hedging of energy and energy-related commodities. We believe that decisions such as those relating to crude slate, yield, total throughput, marketing, distribution, risk management and capital expenditures were likely made to optimize an integrated energy commodities system, as opposed to that of the Memphis refinery specifically. As a result of this and various other factors, we believe we have purchased an asset, rather than a business, from the sellers. Accordingly, we are not providing historical or pro forma financial statements for this acquisition. We intend to optimize the refinery s operations as part of our existing refining system with an emphasis on the production and sale of the refinery s petroleum products.

We believe that our acquisition of the Memphis refinery will benefit us in the following ways:

We expect to achieve growth through the acquisition of a high quality refinery in a niche market. The Memphis refinery is a modern facility and the only refinery in Tennessee. It is strategically located on the Mississippi River, which gives it more immediate access to numerous mid-continent markets with steadily growing demand. We can easily adapt the product slate to meet changing demand patterns in an extensive market

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area. The refinery s location should provide us with a cost advantage over other refiners because it is typically less expensive to ship crude oil to Memphis for refining and subsequent product distribution than to transport refined products to the market area by barge or the TEPPCO pipeline system.

We believe we are acquiring the refinery at an attractive purchase price based on recent refinery transactions. The $315 million purchase price for the refinery assets equates to $1,658 per barrel per day of crude oil throughput capacity, which we believe compares very favorably to the average price paid in recent U.S. refinery asset acquisitions.

We believe the acquisition will be accretive to our earnings per share and will generate positive cash flow from operations. We plan to operate the Memphis refinery at a daily crude oil throughput of approximately 170,000 bpd, which is consistent with its historical operating rate. We also expect that the operating results from the refinery s production will track a Gulf Coast 2/1/1 benchmark crack spread and that we will be able to realize a gross margin benefit over the Gulf Coast 2/1/1 benchmark crack spread resulting from location premiums for refined products, partially offset by crude oil transportation costs. See Management s Discussion and Analysis of Financial Condition and Results of Operations Outlook . Our ability to achieve these results depends on various factors, many of which are beyond our control, including market prices for refined products and crude oil, economic conditions, regulatory environment and unanticipated changes in the Memphis refinery s operations. There can be no assurances that we will achieve our expected results.

We expect that the acquisition will allow us to realize operating and economic synergies with our existing Midwestern refining system. Both the Memphis and Lima refineries process light, sweet crude oil and can be supplied via the Capline pipeline system. We believe we can realize greater efficiencies by acquiring larger water-borne cargoes of foreign crude oils at lower prices. We also believe we will be able to use our Mid-continent terminal system to distribute product that is not marketed in the immediate Memphis area, enabling us to reach markets not currently served by the Memphis refinery, including customers that had previously relied on our recently shut down Hartford refinery.

We expect increased flexibility and cost savings in implementing our plan to comply with new clean fuels regulations. The Memphis refinery should provide us with additional flexibility in complying with Tier 2 gasoline specifications utilizing the corporate pool averaging provision of the regulation. While there can be no assurances, this provision and others set forth in the regulations could allow us to defer a significant portion of the investment required for compliance until the end of 2005 for one or both of the Lima and Memphis refineries. Without the acquisition, our Lima refinery would be required to comply by July 1, 2004.

The sellers estimated that the Memphis refinery s cost for complying with Tier 2 gasoline specifications will be $80 million based on an implementation date of the first quarter of 2004. We are reviewing this estimate and believe there may be opportunities for significant cost savings based on a revised project design and deferral of compliance to 2005. Based on currently available information, we estimate that the cost of complying with low sulfur diesel standards for the Memphis refinery will be approximately $100 million, which would be incurred between 2004 and 2006, with the greatest concentration of spending in 2005. We also do not anticipate the need to spend any capital for MACT II compliance at the Memphis refinery.

The acquisition should enhance and diversify our asset base. With the acquisition of the Memphis refinery, we will increase the number of our operating refineries from two to three and our combined crude oil throughput capacity from 420,000 bpd to 610,000 bpd. The acquisition increases our presence in the attractive PADD II market, where demand has historically exceeded production, creating a strong market environment for refiners. We believe the location advantage of the Memphis refinery will also complement our Port Arthur refinery, which is located in the more competitive PADD III market, but benefits from its significant capacity to process lower-cost heavy sour crude oil.

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USE OF PROCEEDS

We estimate that the net proceeds we will receive from the sale of the shares of our common stock in this offering, after deducting underwriting discounts and commissions and estimated expenses payable by us, will be approximately $239.0 million, or $275.0 million if the underwriters exercise their over-allotment option in full. We expect to receive proceeds of $400.0 million from the issuance of the senior notes in the debt financing. Further, we may receive proceeds of up to $65.0 million from the private equity commitment.

We intend to use a portion of the total net proceeds to finance the Memphis refinery acquisition. However, neither the consummation of this offering nor the consummation of the debt financing is contingent on the other or on the completion of the Memphis refinery acquisition. We will retain broad discretion as to the use of the net proceeds currently allocated to the Memphis refinery acquisition if it is not completed.

In addition, we intend to use approximately $42.4 million of the net proceeds to redeem all of the outstanding 11 1/2% subordinated debentures issued by Premcor USA Inc. and $240.0 million to repay principal under the floating rate notes due 2003 and 2004 issued by PRG. The 11 1/2% subordinated debentures are due in December 2009 and are currently redeemable by Premcor USA at a redemption price equal to 105.75%. As of September 30, 2002, $240.0 million principal amount of floating rate notes due 2003 and 2004 was outstanding, which may be repaid by us at any time at par. See Description of Indebtedness.

In the event that the gross proceeds from this offering and the other financing transactions exceed $650 million in the aggregate due to the purchase of shares by the underwriters pursuant to the over-allotment option or otherwise, we may use the additional gross proceeds to pay for the purchase of inventory at closing or fund our investment in accounts receivable that will result as refinery operations commence. Any inventory purchased by us at closing would not be part of the proposed crude oil supply and product offtake agreement with MSCG.

Pending the uses described above, we intend to invest the net proceeds in direct or guaranteed obligations of the United States, interest-bearing, investment-grade investments or certificates of deposit.

The following table sets forth the expected sources and uses of the proceeds of this offering and the debt financing:

	Amount (in millions)
Sources:	
Proceeds from this offering	$ 250.0
Proceeds from the debt financing	400.0
Total sources	$ 650.0
Uses:	
Purchase of the Memphis refinery and related assets	$ 315.0
Redemption of the 11 1/2% subordinated debentures	42.4
Repayment of the floating rate notes	240.0
General corporate purposes	16.6
Fees and expenses	36.0
Total uses	$ 650.0

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PRICE RANGE OF COMMON STOCK AND DIVIDEND POLICY

Our common stock began trading on the NYSE on April 30, 2002 under the symbol PCO. Before that date, no public market for our common stock existed. Set forth below are the high and low closing sales prices per share of our common stock as reported on the NYSE Composite Tape.

	High	Low
Fiscal Year 2002		
Second Quarter (commencing April 30, 2002)	$ 28.25	$ 24.52
Third Quarter	24.95	15.65
Fourth Quarter	22.93	13.40

On January 21, 2003, the last reported sales price of our common stock on the NYSE was $21.44 per share. As of January 21, 2003, there were 15 shareholders of record.

We do not anticipate paying cash dividends on our common stock in the foreseeable future. We currently intend to retain our future earnings to finance the improvement and expansion of our business. In addition, our ability to pay dividends is effectively limited by the terms of the debt instruments of our subsidiaries, which significantly restrict their ability to pay dividends directly or indirectly to us. See Description of Indebtedness. Future dividends on our common stock, if any, will be at the discretion of our board of directors and will depend on, among other things, our results of operations, cash requirements and surplus, financial condition, contractual restrictions and other factors that our board of directors may deem relevant.

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CAPITALIZATION

The following table sets forth our cash, cash equivalents and short-term investments and capitalization as of September 30, 2002:

- on an actual basis; and
- on an as adjusted basis to reflect:
  - our receipt of the proceeds from the sale of our common stock in this offering;
  - our receipt of the proceeds from the debt financing; and
  - the use of the proceeds from this offering and the debt financing as described under Use of Proceeds.

The table below should be read in conjunction with Summary Financial Data, Selected Financial Data, Management s Discussion and Analysis of Financial Condition and Results of Operations and our condensed consolidated financial statements and the notes to those statements appearing elsewhere in this prospectus.

	As of September 30, 2002	
	Actual	As Adjusted
	(in millions)	
Cash, cash equivalents and short-term investments (1)	$ 209.9	$ 226.5
Debt (2):		
Port Arthur Finance Corp.:		
12 1/2% Senior Secured Notes due 2009	$ 250.7	$ 250.7
Premcor Refining Group:		
Floating Rate Loans due 2003 and 2004	240.0	
8 3/8% Senior Notes due 2007	99.6	99.6
8 5/8% Senior Notes due 2008	109.8	109.8
8 7/8% Senior Subordinated Notes due 2007	174.4	174.4
Ohio Water Development Authority		
Environmental and Facilities Revenue Bonds	10.0	10.0
Senior Notes due 2010 and 2013 to be issued		400.0
Obligations under capital leases	0.7	0.7
Premcor USA:		
11 1/2% Subordinated Debentures due 2009	40.1	
Total debt	925.3	1,045.2
Common stockholders equity:		
Common Stock, $0.01 par value (57,473,935 shares issued and outstanding; 68,973,935 shares issued and outstanding, as adjusted)	0.6	0.7
Paid-in capital	851.6	1,090.5
Retained earnings (deficit)	(193.6)	(195.8)
Total common stockholders equity	658.6	895.4
Total capitalization	$ 1,583.9	$ 1,940.6

(1) Includes $51.9 million of cash restricted for debt service.

(2) In addition, PRG has a credit agreement that provides for the issuance of letters of credit and revolving loan borrowings of up to the lesser of $650 million or the amount available under a borrowing base calculation. As of September 30, 2002, $520.2 million of the line of credit was utilized for the issuance of letters of credit primarily to secure purchases of crude oil. Direct cash borrowings under the credit facility are limited to $50 million. There were no direct cash

borrowings under the facility as of September 30, 2002. In connection with the debt financing and the Memphis refinery acquisition, we must obtain various waivers and approvals under, and extend the maturity date of, this credit agreement. See Description of Indebtedness The Premcor Refining Group Credit Agreement.

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SELECTED FINANCIAL DATA

The following table presents selected financial and other data about us. The selected statement of earnings and cash flow data for the years ended December 31, 1999, 2000, and 2001 and the selected balance sheet data as of December 31, 2000 and 2001 are derived from our consolidated financial statements, including the notes thereto, audited by Deloitte & Touche LLP, independent accountants, appearing elsewhere in this prospectus. The selected statement of earnings and cash flow data for the years ended December 31, 1997 and 1998, and the selected balance sheet data as of December 31, 1997, 1998 and 1999 have been derived from our consolidated financial statements and those of our predecessor, Premcor USA Inc., formerly Clark USA Inc., including the notes thereto, not included in this prospectus, which were audited by Deloitte & Touche LLP. The selected financial data for the nine-month periods ended September 30, 2001 and 2002 and as of September 30, 2002 are derived from our unaudited condensed consolidated financial statements including the notes thereto, appearing elsewhere in this prospectus. The interim information was prepared on a basis consistent with that used in preparing our audited financial statements with only such recurring adjustments as are necessary, in management s opinion, for a fair statement of the results for the periods presented. This selected consolidated financial and other operating data set forth below should be read together with the information contained in Management s Discussion and Analysis of Financial Condition and Results of Operations and our financial statements, including the notes thereto, appearing elsewhere in this prospectus.

	Year Ended December 31,					Nine Months Ended September 30,	
	1997	1998	1999	2000	2001	2001	2002
	(in millions, except per share data)						
Statement of earnings data:							
Net sales and operating revenues	$ 3,880.7	$ 3,581.7	$ 4,520.5	$ 7,301.7	$ 6,417.5	$ 5,170.9	$ 4,807.1
Cost of sales	3,432.1	3,113.2	4,099.8	6,562.5	5,251.4	4,133.7	4,342.8
Gross margin	448.6	468.5	420.7	739.2	1,166.1	1,037.2	464.3
Operating expenses(1)	295.0	342.8	402.8	467.7	467.7	355.8	338.2
General and administrative expenses(1)	43.5	51.2	51.5	53.0	63.3	45.3	40.8
Stock option compensation expense							9.9
Depreciation and amortization (2)	46.8	54.5	63.1	71.8	91.9	67.7	64.9
Inventory write-down (recovery) to market value	19.2	86.6	(105.8)				
Gain on sale of pipeline interest		(69.3)					
Refinery restructuring, recapitalization, asset write-offs and other charges	41.8				176.2	176.2	172.9
Operating income (loss)	2.3	2.7	9.1	146.7	367.0	392.2	(162.4)
Interest expense and finance income, net (3)	(80.1)	(70.5)	(91.5)	(82.2)	(139.5)	(106.3)	(81.5)
Gain (loss) on extinguishment of long-term debt (4)	(20.7)				8.7	8.7	(19.5)
Income tax (provision) benefit	(7.6)	25.0	12.0	25.8	(52.4)	(78.7)	99.9
Minority interest in subsidiary			1.4	(0.6)	(12.8)	(12.4)	1.7
Income (loss) from continuing operations	(106.1)	(42.8)	(69.0)	89.7	171.0	203.5	(161.8)
Discontinued operations, net of taxes(5)	(2.0)	13.1	32.6		(18.0)	(8.5)	
Net income (loss)	(108.1)	(29.7)	(36.4)	89.7	153.0	195.0	(161.8)
Preferred stock dividends	(1.8)	(7.6)	(8.6)	(9.6)	(10.4)	(7.9)	(2.5)
Net income (loss) available to common stockholders	$ (109.9)	$ (37.3)	$ (45.0)	$ 80.1	$ 142.6	$ 187.1	$ (164.3)
Income (loss) from continuing operations per share:							
basic	$ (4.13)	$ (2.54)	$ (3.59)	$ 2.79	$ 5.05	$ 6.15	$ (3.57)
diluted	(4.13)	(2.54)	(3.59)	2.55	4.65	5.67	(3.57)

Weighted average number of common shares outstanding:							
basic	26.1	19.9	21.6	28.8	31.8	31.8	46.0
diluted	26.1	19.9	21.6	31.5	34.5	34.5	46.0

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	Year Ended December 31,					Nine Months Ended September 30,	
	1997	1998	1999	2000	2001	2001	2002
	(in millions, except as noted)						
Cash flow data:							
Cash flow from operating activities	$ 68.2	$ (61.0)	$ 85.5	$ 124.4	$ 439.2	$ 390.2	$ (42.2)
Cash flow from investing activities	(125.6)	(230.7)	(321.3)	(375.3)	(152.9)	(98.5)	(91.8)
Cash flow form financing activities	(46.7)	205.5	393.9	234.8	(66.3)	(68.8)	(219.8)
EBITDA (6)	49.1	57.2	72.2	218.5	458.9	459.9	(97.5)
Adjusted EBITDA (7)	110.1	74.5	(33.6)	218.5	635.1	636.1	75.4
Capital expenditures for property, plant and equipment	27.4	101.4	438.2	390.7	94.5	57.8	64.1
Capital expenditures for turnarounds	47.4	28.3	77.9	31.5	49.2	41.3	33.4
Refinery acquisition expenditures		175.0					
Key operating statistics:							
Production (barrels per day in thousands)	349.3	403.8	460.5	477.3	463.4	459.6	454.8
Crude oil throughput (barrels per day in thousands)	335.1	400.9	451.7	468.0	439.7	438.8	432.4
Per barrel of crude oil throughput:							
Gross margin	$ 3.67	$ 3.20	$ 2.55	$ 4.32	$ 7.27	$ 8.66	$ 3.93
Operating expenses	2.41	2.34	2.44	2.73	2.91	2.97	2.87

	As of December 31,					As of September 30, 2002
	1997	1998	1999	2000	2001	
	(in millions)					
Balance sheet data:						
Cash, cash equivalents and short-term investments (8)	$ 249.2	$ 152.6	$ 307.6	$ 291.8	$ 542.6	$ 209.9
Working capital	454.3	382.6	305.8	325.0	482.6	291.7
Total assets	1,194.9	1,450.3	1,984.1	2,469.1	2,509.8	2,292.5
Total debt	768.4	983.4	1,340.4	1,516.0	1,472.8	925.3
Exchangeable preferred stock	64.8	72.5	81.1	90.6	94.8	
Stockholders equity	38.4	2.2	14.7	152.1	294.7	658.6

(1) Certain reclassifications have been made to prior period amounts to conform them to current period presentation.

(2) Amortization includes amortization of turnaround costs. However, this may not be permitted under GAAP in future periods. See Management s Discussion and Analysis of Financial Condition and Results of Operations Accounting Standards Critical Accounting Standards.

(3) Interest expense and finance income, net, includes amortization of debt issuance costs of $10.6 milion, $2.8 million, $7.9 million, $12.4 million, $14.9 million, $10.9 million and $9.5 million for the years ended December 31, 1997, 1998, 1999, 2000 and 2001, and for the nine months ended September 30, 2001 and 2002, respectively. Interest expense and finance income, net, also includes interest on all indebtedness, net of capitalized interest and interest income.

(4) In the second quarter of 2002, we elected the early adoption of SFAS No. 145 and, accordingly, have included the gain (loss) on extinguishment of long-term debt in Income from continuing operations as opposed to as an extraordinary item, net of taxes, below Income from continuing operations in our Statement of Operations. We have accordingly restated our statement of operations and statement of cash flow for 1997 and 2001.

(5) Discontinued operations is net of income tax provisions of nil, $9.8 million, $21.0 million, and income tax benefits of $11.5 million and $5.5 million in 1997, 1998, 1999 and 2001, and for the nine months ended September 30, 2001, respectively.

(6) Earnings before interest, taxes, depreciation and amortization, or EBITDA, is a commonly used non-GAAP financial measure but should not be construed as an alternative to operating income or net income as an indicator of our performance, nor as an alternative to cash flow from operating activities, investing activities or financing activities as a measure of liquidity, in each case as such measures are determined in accordance

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with GAAP. EBITDA is presented because we believe that it is a useful indicator of a company s ability to incur and service debt. EBITDA, as we calculate it, may not be comparable to similarly-titled measures reported by other companies.

(7) Adjusted EBITDA represents EBITDA excluding refinery restructuring, recapitalization, asset write-offs and other charges of $41.8 million in 1997, $176.2 million in 2001, $176.2 million in the nine months ended September 30, 2001, and $172.9 million in the nine months ended September 30, 2002, gain on sale of pipeline interest of $69.3 million in 1998 and inventory recovery (write-down) to market value of $(19.2) million in 1997, $(86.6) million in 1998, and $105.8 million in 1999. The $176.2 million charge in the full year of 2001 and for the nine months ended September 30, 2001 included $167.2 million related to the closure of our Blue Island refinery. For the nine months ended September 30, 2002, charges of $172.9 million included $137.4 million related to the closure of the Hartford refinery. Adjusted EBITDA is presented because we believe it is a useful indicator to our investors of our ability to incur and service debt based on our ongoing operations. Adjusted EBITDA should not be considered by investors as an alternative to operating income or net income as an indicator of our performance, nor as an alternative to cash flow from operating activities, investing activities or financing activities as a measure of liquidity. Because all companies do not calculate EBITDA identically, this presentation of adjusted EBITDA may not be comparable to EBITDA, adjusted EBITDA or other similarly-titled measures of other companies.

(8) Cash, cash equivalents and short-term investments includes $30.8 million and $51.9 million of cash and cash equivalents restricted for debt service as of December 31, 2001 and September 30, 2002, respectively.

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

Overview

We currently own and operate two refineries with a combined crude oil throughput capacity of approximately 420,000 barrels per day, or bpd. Our refineries are located in Port Arthur, Texas and Lima, Ohio. In late September 2002, we ceased refining operations at our Hartford, Illinois refinery, and we are currently pursuing all strategic options, including expanding the uses of the petroleum product and distribution facility and selling or leasing the refinery, to mitigate the loss of jobs and refinery capacity in the Midwest. We continue to operate the terminal facility at the Hartford refinery in connection with our wholesale petroleum product distribution business. Our Port Arthur refinery has the capacity to process substantial volumes of low-cost sour and heavy sour crude oil, resulting in lower feedstock costs, a distinct competitive advantage. Our heavy sour crude oil processing capacity is approximately 50% of throughput on a company-wide basis and 80% of throughput at our Port Arthur refinery, which possesses one of the world s largest coking units. For the nine months ended September 30, 2002, light products accounted for approximately 90% of our total product volume. For the same period, high-value, premium product grades, such as high octane and reformulated gasoline, low-sulfur diesel and jet fuel, which are the most valuable types of light products, accounted for approximately 40% of our total product volume. For further detail on our business, see Business .

Developments in 2002

Memphis Refinery Acquisition

On November 25, 2002, we executed an agreement with The Williams Companies, Inc. and certain of its subsidiaries to purchase their Memphis, Tennessee refinery and related supply and distribution assets. The purchase price for the refinery and the other assets is $315 million, plus the value of inventories at closing. At current price levels, the value of the inventories is estimated to be $200 million. The agreement also provides for earn-out payments that could result in additional payments of $75 million by us to Williams over the next seven years, depending on the level of industry refining margins during that period.

The Memphis refinery has a rated crude oil throughput capacity of 190,000 bpd but typically processes approximately 170,000 bpd. The related assets include two truck-loading racks; three petroleum terminals in the area; supporting pipeline infrastructure that transports both crude oil and refined products; crude oil tankage at St. James, Louisiana; and an 80 megawatt power plant adjacent to the refinery.

We believe we are acquiring a quality refinery at an attractive price that will produce operating and economic synergies and that should be accretive to our earnings per share and generate positive cash flow from operations. Completion of the acquisition is subject to our obtaining the necessary financing and the satisfaction of customary conditions, including regulatory approvals. We intend to finance the refinery and the related assets with the proceeds from this offering and the other financing transactions. We expect the acquisition to close during the first quarter of 2003. For more details concerning the acquisition of the Memphis refinery, see The Acquisition of the Memphis Refinery.

Initial Public Offering

On May 3, 2002, we completed an initial public offering of 20.7 million shares of common stock. The initial public offering, plus the concurrent purchases of 850,000 shares in the aggregate by Thomas D. O Malley, our chairman of the board and chief executive officer, and two of our directors, netted proceeds of approximately $482 million. The proceeds from the offering were committed to retiring certain indebtedness of our subsidiaries.

Sabine Restructuring

On June 6, 2002, we completed a series of transactions, referred to as the Sabine restructuring, that resulted in Sabine River Holding Corp., or Sabine, and its subsidiaries becoming wholly owned subsidiaries of PRG. Prior to the Sabine restructuring, Sabine was 90% owned by us and 10% owned by Occidental. Sabine, through its principal operating subsidiary, Port Arthur Coker Company L.P., or PACC, owns and operates a heavy oil processing facility, which is operated in conjunction with PRG s Port Arthur, Texas refinery. PACC owns all of the outstanding common stock of Port Arthur Finance Corp., or PAFC.

The Sabine restructuring was permitted by the successful consent solicitation of the holders of PAFC s 12½% senior notes. The Sabine restructuring was accomplished according to the following steps, among others:

- We contributed $225.6 million in proceeds from our initial public offering of common stock to Sabine. Sabine used the proceeds from the equity contribution, plus cash on hand, to prepay $221.4 million of its senior secured bank loan and to pay a dividend of $141.4 million to us;

- Commitments under Sabine s senior secured bank loan, working capital facility, and certain insurance policies were terminated and related guarantees were released;

- PRG s existing working capital facility was amended and restated to, among other things, permit letters of credit to be issued on behalf of Sabine;

- Occidental exchanged its 10% interest in Sabine for 1,363,636 newly issued shares of our common stock;

- We contributed our 100% ownership interest in Sabine to our wholly owned subsidiary, Premcor USA, and Premcor USA, in turn, contributed its 100% ownership interest to its wholly owned subsidiary, PRG; and

- PRG fully and unconditionally guaranteed, on a senior unsecured basis, the payment obligations under the 12½% senior notes.

Our acquisition of Occidental s 10% ownership in Sabine was accounted for under the purchase method. The purchase price was based on the exchange of 1,363,636 shares of our common stock for the 10% interest in Sabine and was valued at $30.5 million or approximately $22 per share. The purchase price of the 10% minority interest in Sabine exceeded the book value by $8.0 million. Based on an appraisal of the Sabine assets, the excess of the purchase price over the book value of the minority interest, along with a $5.0 million deferred income tax adjustment, was recorded as an investment in property, plant and equipment and will be depreciated over the remaining useful lives of the related Sabine assets. The income tax adjustment reflected the temporary difference between the book and tax basis of property, plant and equipment related to the excess of the purchase price over book value. Because the purchase price did not exceed the fair value of the underlying assets, no goodwill was recognized.

Factors Affecting Comparability

Our results over the past three years and over the nine months ended September 30, 2001 and 2002 have been influenced by the following events, which must be understood in order to assess the comparability of our period-to-period financial performance.

Inventory Price Risk Management. The nature of our business leads us to maintain a substantial investment in petroleum inventories. Since petroleum feedstocks and products are essentially commodities, we have no control over the changing market value of our investment. We manage the impact of commodity price volatility on our hydrocarbon inventory position by, among other methods, determining a volumetric exposure level that we consider appropriate and consistent with normal business operations. This target inventory position includes both titled inventory and fixed price purchase and sale commitments. The portion of our current target

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inventory position consisting of sales commitments netted against fixed price purchase commitments amounts to a net long inventory position of approximately 4 million barrels.

Prior to the second quarter of 2002, we did not generally price protect any portion of our target inventory position. However, although we continue to generally leave the titled portion of our inventory position target fully exposed to price fluctuations, beginning in the second quarter of 2002, we began to actively mitigate some or all of the price risk related to our target level of fixed price purchase and sale commitments. These risk management decisions are based on the relative level of absolute hydrocarbon prices. The cumulative economic effect of our risk management strategy in the second and third quarter of 2002 resulted in an approximate $11 million loss as measured against a fully exposed fixed price commitment target. In the first quarter of 2002, we benefited by approximately $30 million from having our fixed price commitment target fully exposed in a rising absolute price environment.

We generally conduct our risk mitigation activities through the purchase or sale of futures contracts on the New York Mercantile Exchange, or NYMEX. Our price risk mitigation activities carry all of the usual time, location and product grade basis risks generally associated with these activities. Because our titled inventory is valued under the last-in, first-out costing method, price fluctuations on our target level of titled inventory have very little effect on our financial results unless the market value of our target inventory is reduced below cost. However, since the current cost of our inventory purchases and sales are generally charged to our statement of operations, our financial results are affected by price movements on the portion of our target level of fixed price purchase and sale commitments that are not price protected.

Operation of the Port Arthur Heavy Oil Upgrade Project. In January 2001, we began operating our heavy oil upgrade project at our Port Arthur refinery. The project, which began construction in 1998, included the construction of a new 80,000 bpd delayed coking unit, a 35,000 bpd hydrocracker, a 417 ton per day sulfur removal unit and the expansion of the existing crude unit capacity to 250,000 bpd. The heavy oil upgrade project allows the refinery to process primarily lower-cost, heavy sour crude oil. We financed the construction of the new facilities with the proceeds from new indebtedness issued by our PAFC subsidiary and with new equity contributions from our principal shareholders, Blackstone and Occidental. Start-up of the project occurred in stages, with the sulfur removal units and the coker unit beginning operations in December 2000 and the hydrocracker unit beginning operations in January 2001. Performance and substantial reliability testing of the project was completed in the third quarter of 2001, and final completion of the project was achieved on December 28, 2001.

The comparability of our results is significantly influenced by the impact of the heavy oil upgrade project. In 2000, our Port Arthur refinery processed an average of 202,100 bpd of crude oil. Of that amount, 43,400 bpd, or 21.5%, represented heavy sour crude oil, primarily Maya crude oil, and had an average processed value of $8.00 per barrel less than the equivalent per barrel value of West Texas Intermediate crude oil, a benchmark sweet crude oil. The remaining 158,700 bpd, or 78.5%, consisted of medium sour, light sour and sweet crude oils valued at an average discount to West Texas Intermediate of $1.57 per barrel. In total, the 202,100 bpd of crude oil processed by our refinery during 2000 had a value, on the day of processing, of $218.4 million less than the value of an equivalent volume of West Texas Intermediate crude oil, representing a discount to West Texas Intermediate crude oil of $2.95 per barrel.

In contrast, in 2001, including the start-up of the heavy oil upgrade project, our Port Arthur refinery processed an average of 229,800 bpd of crude oil. Of that amount, 181,500 bpd, or 79.0%, represented heavy sour crude oil, all of which was Maya crude oil, and had an average processed value of $8.84 per barrel less than the equivalent per barrel value of West Texas Intermediate crude oil. The remaining 48,300 bpd, or 21.0%, was medium sour crude oil valued at a discount to West Texas Intermediate crude oil of $4.73 per barrel. As a result of the refinery upgrade, our Port Arthur refinery no longer processes sweet and light sour crude oils. In total, the 229,800 bpd of crude oil processed by the refinery during 2001 had a value, on the day of processing, of $669.0 million less than the value of an equivalent volume of West Texas Intermediate crude oil, representing a discount to West Texas Intermediate crude oil of $7.98 per barrel.

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Although the heavy oil upgrade project has enabled us to process a less costly crude oil slate, the overall value of the resulting product slate is lower due to increased production of petroleum coke and other lower-valued products. In addition, the operating cost structure is higher under the new configuration of the Port Arthur refinery. Our operating results for 2001 and for the nine months ended September 30, 2002 demonstrate that the benefit of the less expensive crude oil slate exceeds the lower product realization and higher operating costs. For further discussion of our operating results see Results of Operations Nine Months Ended September 30, 2002 Compared to Nine Months Ended September 30, 2001 and Results of Operations 2001 Compared to 2000.

Closure of Blue Island Refinery. In January 2001, we ceased operations at our Blue Island, Illinois refinery due to economic factors and a decision that the capital expenditures necessary to produce low-sulfur transportation fuels required by recently adopted EPA regulations could not produce acceptable returns on investment. This closure resulted in a pretax charge of $167.2 million for 2001. We continue to utilize our petroleum products storage facility at the refinery site to supply selected products to the Chicago and other Midwest markets from our operating refineries. Since the Blue Island refinery operation had been only marginally profitable in recent years and since we will continue to operate a petroleum products storage and distribution business from the Blue Island site, our reduced refining capacity resulting from the closure is not expected to have a significant negative impact on net income or cash flow from operations. The only significant effect on net income and cash flow will result from the subsequent environmental site remediation as discussed below. Unless there is a need to adjust the closure reserve in the future, there should be no significant effect on net income beyond 2001.

Management adopted an exit plan that detailed the shutdown of the process units at the refinery and the subsequent environmental remediation of the site. The shutdown of the process units was completed during the first quarter of 2001. The Blue Island refinery employed 297 employees, both hourly employees covered by collective bargaining agreements and salaried employees, the employment of 293 of which was terminated during 2001 and the remainder in 2002. A pretax charge of $150.0 million was recorded in the first quarter of 2001 and an additional charge of $17.2 million was recorded in the third quarter of 2001. The original charge included $92.5 million of non-cash asset write-offs in excess of realizable value and a reserve for future costs of $57.5 million, consisting of $12.0 million for severance, $26.4 million for the ceasing of operations, preparation of the plant for permanent closure and equipment remediation and $19.1 million for site remediation and other environmental matters. The third quarter charge of $17.2 million included an adjustment of $5.6 million to the asset write-off to reflect changes in realizable asset value and an increase to the reserve of $11.6 million related to an evaluation of expected future expenditures. The following schedule summarizes the restructuring reserve balance and net cash activity as of September 30, 2002:

	Reserve as of December 31, 2001	Net Cash Outlays	Reserve as of September 30, 2002
Employee severance	$ 2.1	$ 2.1	$
Plant closure/equipment remediation	13.9	8.1	5.8
Site clean-up/environmental matters	20.5	3.9	16.6
	$ 36.5	$ 14.1	$ 22.4

We expect to spend approximately $15 million to $16 million in 2002 related to the reserve for future costs, with the remainder to be spent over the next several years. We are currently in discussions with governmental agencies concerning a remediation program, which we believe will likely lead to a final consent order and remediation plan. We do not expect these discussions to be concluded until 2003 at the earliest. Our site clean-up and environmental reserve takes into account costs that are reasonably foreseeable at this time, based on studies performed in conjunction with obtaining the insurance policy mentioned below. As the site remediation plan is finalized and work is performed, further adjustments of the reserve may be necessary.

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In 2002, environmental risk insurance policies covering the Blue Island refinery site were procured and bound, with final policies expected to be issued within the first quarter of 2003. This insurance program will allow us to quantify and, within the limits of the policy, cap our cost to remediate the site, and provide insurance coverage from future third party claims arising from past or future environmental releases. The remediation cost overrun policy has a term of ten years and, subject to certain exceptions and exclusions, provides $25 million in coverage in excess of a self-insured retention amount of $26 million. The pollution legal liability policy provides for $25 million in aggregate coverage and per incident coverage in excess of a $100,000 deductible per incident. We believe this program also provides governmental agencies financial assurance that, once begun, remediation of the site will be completed in a timely and prudent manner.

Sale of Product Terminals. In December 1999, we sold 15 refined product terminals, mainly located in the Midwest for net cash proceeds of approximately $34 million. We have entered into a refined product exchange agreement with an affiliate of the buyer to broaden our wholesale geographical distribution capabilities in the Midwest and expand our distribution capability nationally.

Sale of Retail Division. In 1999, we sold our retail marketing division for approximately $230 million, while maintaining an approximately 5% equity interest. The retail division included all company and independently operated Clark-branded stores and the Clark trade name. After all transaction costs, the sale generated cash proceeds of approximately $215 million. The retail marketing operations were classified as discontinued operations in our consolidated statements of operations for all periods presented. A pretax gain on the sale of $60.6 million, or $36.9 million net of income taxes, was recognized in the third quarter of 1999 and is included in our discontinued operations line item.

In 2001, we recorded an additional pretax charge of $29.5 million, or $18.0 million net of income taxes, related to the environmental and other liabilities of our discontinued retail operations. This charge represents an increase in our estimates regarding our environmental clean up obligations and workers compensation liability and a decrease in the estimated amount of reimbursements for environmental expenditures that are collectible from state agencies under various programs. The change in estimates was prompted by the availability of new information concerning site by site clean-up plans, changing postures of state regulatory agencies, and fluctuations in the amounts available under state reimbursement programs.

Factors Affecting Operating Results

Our earnings and cash flow from operations are primarily affected by the relationship between refined product prices and the prices for crude oil and other feedstocks. The cost to acquire feedstocks and the price of refined products ultimately sold depends on numerous factors beyond our control, including the supply of, and demand for, crude oil, gasoline and other refined products which, in turn, depend on, among other factors, changes in domestic and foreign economies, weather conditions, domestic and foreign political affairs, production levels, the availability of imports, the marketing of competitive fuels and the extent of government regulation. While our net sales and operating revenues fluctuate significantly with movements in industry crude oil prices, such prices do not generally have a direct long-term relationship to net earnings. Crude oil price movements may impact net earnings in the short term because of fixed price crude oil purchase commitments. The effect of changes in crude oil prices on our operating results is influenced by how the prices of refined products adjust to reflect such changes in crude oil prices.

Feedstock and refined product prices are also affected by other factors, such as product pipeline capacity, local market conditions and the operating levels of competing refineries. Crude oil costs and the price of refined products have historically been subject to wide fluctuation. Expansion of existing facilities and installation of additional refinery crude distillation and upgrading facilities, price volatility, international political and economic developments and other factors beyond our control are likely to continue to play an important role in refining industry economics. These factors can impact, among other things, the level of inventories in the market resulting

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in price volatility and a reduction in product margins. Moreover, the industry typically experiences seasonal fluctuations in demand for refined products, such as increases in the demand for gasoline during the summer driving season and for home heating oil during the winter, primarily in the Northeast. For example, three consecutive unseasonably warm winters in the Northeast resulted in reduced demand, unusually high inventories and considerably lower prices for heating oil during 1999. For further details on the economics of refining, see Industry Overview Economics of Refining.

In order to assess our operating performance, we compare our gross margin (net sales and operating revenue less cost of sales) against an industry gross margin benchmark. The industry gross margin is calculated by assuming that three barrels of benchmark light sweet crude oil is converted, or cracked, into two barrels of conventional gasoline and one barrel of high-sulfur diesel fuel. This is referred to as the 3/2/1 crack spread. Since we calculate the benchmark margin using the market value of United States Gulf Coast gasoline and diesel fuel against the market value of West Texas Intermediate crude oil, we refer to the benchmark as the Gulf Coast 3/2/1 crack spread, or simply, the Gulf Coast crack spread. The Gulf Coast crack spread is expressed in dollars per barrel and is a proxy for the per barrel margin that a sweet crude oil refinery situated on the Gulf Coast would earn assuming it produced and sold the benchmark production of conventional gasoline and high-sulfur diesel fuel. As explained below, each of our refineries, depending on market conditions, has certain feedstock cost and/or product value advantages as compared to the benchmark refinery, and as a result, our gross margin per barrel of throughput generally exceeds the Gulf Coast crack spread.

Our Port Arthur refinery is able to process significant quantities of sour and heavy sour crude oil that have historically cost less than West Texas Intermediate crude oil. We measure the cost advantage of heavy sour crude oil by calculating the spread between the value of Maya crude oil, a heavy crude oil produced in Mexico, to the value of West Texas Intermediate crude oil, a light crude oil. We use Maya for this measurement because a significant amount of our long-term supply of heavy crude oil throughput is Maya. We measure the cost advantage of sour crude oil by calculating the spread between the throughput value of West Texas Sour crude oil to the value of West Texas Intermediate crude oil. In addition, since we are able to source both domestic pipeline crude oil and foreign tanker crude oil to each of our refineries, the value of foreign crude oil relative to domestic crude oil is also an important factor affecting our operating results. Since many foreign crude oils, other than Maya, are priced relative to the market value of a benchmark North Sea crude oil known as Dated Brent, we also measure the cost advantage of foreign crude oil by calculating the spread between the value of Dated Brent crude oil to the value of West Texas Intermediate crude oil.

We have crude oil supply contracts with PMI Comercio Internacional, S.A. de C.V., an affiliate of Petroleos Mexicanos (PEMEX), the Mexican state oil company, that provide for our purchase of approximately 200,000 bpd of crude oil under two separate contracts. One of these contracts is a long-term agreement, under which we currently purchase approximately 162,000 bpd, designed to provide us with a stable and secure supply of Maya crude oil. An important feature of this agreement is a price adjustment mechanism designed to minimize the effect of adverse refining margin cycles and to moderate the fluctuations of the coker gross margin, a benchmark measure of the value of coker production over the cost of coker feedstocks. This price adjustment mechanism contains a formula that represents an approximation of the coker gross margin and provides for a minimum average coker gross margin of $15 per barrel over the first eight years of the agreement, which began on April 1, 2001. The agreement expires in 2011. For purpose of comparison, the $15 per barrel minimum average coker gross margin support amount equates to a WTI/Maya crude oil price differential of approximately $6 per barrel using market prices during the period from 1988 to 2002, which slightly exceeds actual market differentials during that period.

On a monthly basis, the coker gross margin, as defined under this agreement, is calculated and compared to the minimum. Coker gross margins exceeding the minimum are considered a surplus while coker gross margins that fall short of the minimum are considered a shortfall. On a quarterly basis, the surplus and shortfall determinations since the beginning of the contract are aggregated. Pricing adjustments to the crude oil we purchase are only made when there exists a cumulative shortfall. When this quarterly aggregation first reveals

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that a cumulative shortfall exists, we receive a discount on our crude oil purchases in the next quarter in the amount of the cumulative shortfall. If thereafter, the cumulative shortfall incrementally increases, we receive additional discounts on our crude oil purchases in the succeeding quarter equal to the incremental increase, and conversely, if thereafter, the cumulative shortfall incrementally decreases, we repay discounts previously received, or a premium, on our crude oil purchases in the succeeding quarter equal to the incremental decrease. Cash crude oil discounts received by us in any one quarter are limited to $30 million, while our repayment of previous crude oil discounts, or premiums, are limited to $20 million in any one quarter. Any amounts subject to the quarterly payment limitations are carried forward and applied in subsequent quarters.

As of September 30, 2002, a cumulative quarterly surplus of $61.7 million existed under the contract. As a result, to the extent we experience quarterly shortfalls in our coker gross margins going forward, the price we pay for Maya crude oil in succeeding quarters will not be discounted until this cumulative surplus is offset by future shortfalls. Assuming the WTI less Maya crude oil differential continues at its third quarter 2002 average of $4.92 per barrel, and assuming a Gulf Coast 3/2/1 crack spread similar to the third quarter 2002 average of $2.64 per barrel, we estimate the current $61.7 million cumulative surplus would be fully reversed after the third quarter of 2003. At that time, assuming a continuation of weak market conditions, we would be eligible to receive discounts on our crude oil purchases under the long-term contract with the PEMEX affiliate as described above.

Other than the long-term contract with the PEMEX affiliate, our crude oil supply contracts are generally terminable upon one to three months notice by either party. We acquire the majority of the remainder of our crude oil supply on the spot market from unaffiliated foreign and domestic sources, allowing us to be flexible in our crude oil supply source.

The sales value of our production is also an important consideration in understanding our results. We produce a high volume of premium products, such as high octane, or premium and reformulated gasoline, low-sulfur diesel, jet fuel and petrochemical products that carry a sales value significantly greater than that for the products used to calculate the Gulf Coast crack spread. In addition, products produced by our Lima refinery are generally of higher value than similar products produced on the Gulf Coast due to the fact that the Midwest consumes more refined products than it produces, thereby creating a competitive advantage for Midwest refiners that can produce and deliver refined products at a cost lower than importers of refined products into the region. This advantage is measured by the excess of the Chicago crack spread over the Gulf Coast crack spread plus or minus the differential in the cost of transporting crude oil versus refined products to the region. The Chicago crack spread is determined by replacing the published Gulf Coast product values in the Gulf Coast crack spread with published Chicago product values.

Another important factor affecting operating results is the relative quantity of higher value transportation fuels and petrochemical feedstocks we produce compared to the production of lower value residual fuel oil and other by-products we produce, such as petroleum coke and sulfur. Our Lima refinery produces a product slate that is of significantly higher value than the products used to calculate the Gulf Coast crack spread. Our Lima refinery also benefits from its mid-continental location, in addition to the fact that it produces a greater percentage of high value transportation fuels as a result of processing a predominantly sweet crude oil slate. In contrast to our Lima refinery, our Port Arthur refinery produces a product slate that approximates the value of the products used to calculate the Gulf Coast crack spread. Although the significant shift to heavy sour crude oil resulting from the completion of the heavy oil upgrade project has slightly lowered the overall value of the products produced at the refinery, the lower crude oil costs has greatly exceeded the decline in product value.

Our operating cost structure is also important to our profitability. Major operating costs include costs relating to energy, employee and contract labor, maintenance and environmental compliance. The predominant variable cost is energy and the most important benchmark for energy costs is the value of natural gas. Because the complexity of our Port Arthur refinery and its ability to process significantly greater volumes of heavy sour crude oil increased significantly as a result of the heavy oil upgrade project, it now has a higher operating cost structure, primarily related to energy and labor.

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Safety, reliability, and the environmental performance of our refinery operations are critical to our financial performance. Unplanned downtime of our refinery assets generally results in lost margin opportunity, increased maintenance expense and a temporary increase in working capital investment and related inventory position. If we choose to hedge the incremental inventory position, we are subject to market and other risks normally associated with hedging activities. The financial impact of planned downtime, such as major turnaround maintenance, is mitigated through a diligent planning process that considers such things as margin environment, the availability of resources to perform the needed maintenance, and feedstock logistics.

The nature of our business leads us to maintain a substantial investment in petroleum inventories. Since petroleum feedstocks and products are essentially commodities, we have no control over the changing market value of our investment. We manage the impact of commodity price volatility on our hydrocarbon inventory position by, among other methods, determining a volumetric exposure level that we consider to be appropriate and consistent with normal business operations. This target inventory position includes both titled inventory and fixed price purchase and sale commitments. The portion of our current target inventory position consisting of sales commitments netted against fixed price purchase commitments amounts to a net long inventory position of approximately 4 million barrels. We are generally leaving the titled portion of our inventory position target fully exposed to price fluctuations; however, beginning in the second quarter of 2002, we began to actively mitigate some or all of the price risk related to our target level of fixed price purchase and sale commitments. These risk management decisions are based on the relative level of absolute hydrocarbon prices. We generally conduct our risk mitigation activities through the purchase or sale of futures contracts on the New York Mercantile Exchange, or NYMEX. Our price risk mitigation activities carry all of the usual time, location and product grade basis risks generally associated with these activities. Because our titled inventory is valued under the last-in, first-out costing method, price fluctuations on our target level of titled inventory have very little effect on our financial results unless the market value of our target inventory is reduced below cost. However, since the current cost of our inventory purchases and sales are generally charged to our statement of operations, our financial results are affected by price movements on the portion of our target level of fixed price purchase and sale commitments that are not price protected.

Results of Operations

The following tables provide supplementary income statement and operating data. Selected items in each of the periods are discussed separately below.

Net sales and operating revenues consist principally of sales of refined petroleum products and, to a minimal extent, the occasional sale of crude oil to take advantage of substitute crude slate opportunities. Cost of sales consists of the purchases of crude oils and other feedstocks used in the refining process as well as transportation, inventory management and other costs associated with the refining process and sale of the petroleum products. Both net sales and operating revenues and cost of sales are mainly affected by crude oil and refined product prices, changes to the input and product mix, and volume changes caused by acquisitions, divestitures and operations. Product mix refers to the percentage of production represented by higher value light products, such as gasoline, rather than lower value finished products, such as petroleum coke.

Gross margin is net sales and operating revenues less cost of sales. Industry-wide results are driven and measured by the relationship, or margin, between refined product prices and the prices for crude oil and other feedstocks; therefore, we discuss our results of operations in the context of gross margin.

Operating expenses include the costs associated with the actual operations of our plants, such as labor, maintenance, energy, taxes and environmental compliance. All environmental compliance costs, other than capital expenditures but including maintenance and monitoring, are expensed when incurred. The labor costs include the incentive compensation plans available to union employees. Our general and administrative expenses include all activities at the executive and corporate offices, the finance, human resources and information system activities at the refineries and the company-wide incentive compensation programs available to salaried employees.

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Inventory recovery (write-down) to market reflects a non-cash accounting adjustment to the value of our petroleum inventory. In accordance with GAAP, we are required to record our inventory at the lower of its cost or market value. In late 1997 and throughout 1998, market prices were significantly less than cost determined under our last-in, first-out, or LIFO, inventory valuation method. This led to market write-downs of inventory in 1997 and 1998. In 1999, our inventory turned over and market prices recovered allowing us to fully reverse our 1997 and 1998 write-downs.

Minority interest represents Occidental s 10% interest in our subsidiary, Sabine, prior to the restructuring.

	Year Ended December 31,			Nine Months Ended September 30,	
	1999	2000	2001	2001	2002
Financial results	(in millions, except per share data)				
Net sales and operating revenue	$ 4,520.5	$ 7,301.7	$ 6,417.5	$ 5,170.9	$ 4,807.1
Cost of sales	4,099.8	6,562.5	5,251.4	4,133.7	4,342.8
Gross margin	420.7	739.2	1,166.1	1,037.2	464.3
Operating expenses	402.8	467.7	467.7	355.8	338.2
General and administrative expenses	51.5	53.0	63.3	45.3	40.8
Stock option compensation expense					9.9
Adjusted EBITDA	(33.6)	218.5	635.1	636.1	75.4
Inventory recovery from market write-down	(105.8)				
Refinery restructuring and other charges			176.2	176.2	172.9
EBITDA	72.2	218.5	458.9	459.9	(97.5)
Depreciation and amortization	63.1	71.8	91.9	67.7	64.9
Operating income (loss)	9.1	146.7	367.0	392.2	(162.4)
Interest expense and finance income, net	(91.5)	(82.2)	(139.5)	(106.3)	(81.5)
Gain (loss) on extinguishment of long-term debt			8.7	8.7	(19.5)
Income tax (provision) benefit	12.0	25.8	(52.4)	(78.7)	99.9
Minority interest	1.4	(0.6)	(12.8)	(12.4)	1.7
Income (loss) from continuing operations	(69.0)	89.7	171.0	203.5	(161.8)
Discontinued operations	32.6		(18.0)	(8.5)	
Net income (loss)	(47.0)	89.7	153.0	195.0	(161.8)
Preferred stock dividends	(8.6)	(9.6)	(10.4)	(7.9)	(2.5)
Net income (loss) available to common stockholders	$ (45.0)	$ 80.1	$ 142.6	$ 187.1	$ (164.3)
Income (loss) from continuing operations per common share:					
Basic	$ (3.59)	$ 2.79	$ 5.05	$ 6.15	$ (3.57)
Diluted	(3.59)	2.55	4.65	5.67	(3.57)
Weighted average common shares outstanding:					
Basic	21.6	28.8	31.8	31.8	46.0
Diluted	21.6	31.5	34.5	34.5	46.0

	Year Ended December 31,			Nine Months Ended September 30,	
	1999	2000	2001	2001	2002
Market indicators	(dollars per barrel, except as noted)				
West Texas Intermediate (WTI) crude oil	$ 19.27	$ 30.37	$ 25.96	$ 27.84	$ 25.41

Crack Spreads:					
Gulf Coast 3/2/1	1.71	4.17	4.22	4.98	2.93
Gulf Coast 2/1/1	1.37	4.02	3.92	4.54	2.42
Chicago 3/2/1	2.83	5.84	7.90	9.04	4.59
Crude Oil Differentials:					
WTI less WTS (sour)	1.30	2.17	2.81	3.11	1.26
WTI less Maya (heavy sour)	4.83	7.29	8.76	9.57	4.90
WTI less Dated Brent (foreign)	1.36	1.92	1.48	1.68	1.01
Natural gas (dollars per million btus)	2.25	3.94	4.22	4.90	2.92

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Selected Operational Data	Year Ended December 31, 1999	Year Ended December 31, 2000	Year Ended December 31, 2001	Nine Months Ended September 30, 2001	Nine Months Ended September 30, 2002
	(in thousands of barrels per day, except as noted)				
Crude oil throughput by refinery:					
Port Arthur	200.0	202.1	229.8	225.2	229.1
Lima	120.7	136.4	140.5	143.0	141.0
Hartford	59.4	64.2	65.5	65.3	62.3
Blue Island	71.6	65.3	3.9	5.3	
Total crude oil throughput	451.7	468.0	439.7	438.8	432.4
Per barrel of throughput (in dollars):					
Gross margin	$ 2.55	$ 4.32	$ 7.27	$ 8.66	$ 3.93
Operating expenses	2.44	2.73	2.91	2.97	2.87

Selected Volumetric Data	Year Ended December 31, 1999 bpd (thousands)	1999 Percent of Total	2000 bpd (thousands)	2000 Percent of Total	2001 bpd (thousands)	2001 Percent of Total	Nine Months Ended September 30, 2001 bpd (thousands)	2001 Percent of Total	2002 bpd (thousands)	2002 Percent of Total
Feedstocks:										
Crude oil throughput:										
Sweet	195.3	42.8%	201.5	42.6%	143.6	31.9%	147.0	33.0%	137.7	31.6%
Light/medium sour	220.1	48.2	207.4	44.0	107.7	23.9	109.5	24.5	101.9	23.4
Heavy sour	36.3	8.0	59.1	12.4	188.4	41.8	182.3	40.9	192.8	44.2
Total crude oil	451.7	99.0	468.0	99.0	439.7	97.6	438.8	98.4	432.4	99.2
Unfinished and blendstocks	4.6	1.0	4.6	1.0	10.6	2.4	7.3	1.6	3.9	0.8
Total feedstocks	456.3	100.0%	472.6	100.0%	450.3	100.0%	446.1	100.0%	436.3	100.0%
Production:										
Light Products:										
Conventional gasoline	174.6	37.9%	193.0	40.4%	184.8	39.9%	182.5	39.7%	186.5	41.0%
Premium and reformulated gasoline	67.1	14.6	57.8	12.1	44.9	9.7	47.1	10.2	39.3	8.6
Diesel fuel	119.4	25.9	117.8	24.7	121.7	26.3	118.6	25.8	102.9	22.6
Jet fuel	35.8	7.8	38.0	8.0	42.4	9.1	41.8	9.1	49.8	11.0
Petrochemical feedstocks	34.5	7.5	36.2	7.6	28.5	6.2	29.0	6.3	28.8	6.3
Total light products	431.4	93.7	442.8	92.8	422.3	91.2	419.0	91.1	407.3	89.5
Petroleum coke and sulfur	17.8	3.9	19.0	4.0	33.1	7.1	33.4	7.3	36.8	8.1
Residual oil	11.3	2.4	15.5	3.2	8.0	1.7	7.2	1.6	10.7	2.4
Total production	460.5	100.0%	477.3	100.0%	463.4	100.0%	459.6	100.0%	454.8	100.0%

Nine Months Ended September 30, 2002 Compared to Nine Months Ended September 30, 2001

Overview. Our net loss to common stockholders was $164.3 million ($3.57 per diluted share) in the first nine months of 2002 as compared to net income available to common stockholders of $187.1 million ($5.42 per diluted share) in the corresponding period in 2001. Our operating loss was $162.4 million in the first nine months of 2002 as compared to operating income of $392.2 million in the corresponding period in 2001. Operating income (loss) included pretax refinery restructuring and other charges of $172.9 million and $176.2 million in the first nine months of 2002 and 2001, respectively. Excluding the refinery restructuring and other charges, our operating income was $10.5 million and $568.4 million in the first nine months of 2002 and 2001, respectively. Operating income, excluding the refinery restructuring and other charges, decreased in the first nine months of 2002 compared to the same period in 2001 principally due to significantly weaker market conditions in 2002 than in 2001.

Net Sales and Operating Revenues. Net sales and operating revenues decreased $363.8 million, or 7%, to $4,807.1 million in the first nine months of 2002 from $5,170.9 million in the corresponding period in 2001. This decrease was mainly attributable to lower average product prices in the first nine months of 2002 as compared to

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the same period of 2001. The overall price decline in 2002 reflects the weaker market conditions in 2002 versus the higher product prices mainly observed in the first six months of 2001. This decrease was partially offset by higher product prices in the third quarter of 2002, which we believe were influenced by uncertainties about war with Iraq and associated concerns about future crude oil supply.

Gross Margin. Gross margin decreased $572.9 million to $464.3 million in the first nine months of 2002 from $1,037.2 million in the corresponding period in 2001. This decrease in gross margin was principally driven by significantly weaker market conditions in 2002 than in 2001.

Market

These weak market conditions consisted of significantly weaker crack spreads and crude oil differentials. Beginning in late 2001 and continuing into the third quarter of 2002, on an overall basis, crack spreads have been poor due to weak demand and high levels of distillate and gasoline inventories. This margin environment has been principally driven by a sluggish world economy, significant declines in air travel following the events of September 11, 2001, and an extremely mild 2001/2002 winter. The normal increase in demand for the spring and summer driving season contributed slight improvements to the crack spreads in the second quarter; however, the third quarter again reflected depressed conditions. The Gulf Coast and Chicago crack spreads were approximately 40-50% lower in the first nine months of 2002 than in the corresponding period of 2001. The third quarter of 2001 reflected a decrease from historic highs reached earlier in that year in the Gulf Coast crack spreads as supply shortages from early in the year were addressed with high refinery utilization rates and increased import levels. The Chicago crack spreads did not weaken in proportion to the Gulf Coast crack spreads in the third quarter of 2001 due primarily to supply shortages caused by an unplanned, extended outage at a Chicago refinery, as well as other factors.

The crude oil differentials were also significantly lower in the first nine months of 2002 as compared to the same period in 2001. The crude oil differential between WTI and Maya heavy sour crude oil was approximately 50% lower for the first nine months of 2002 than for the same period last year, and the crude oil differential between WTI and WTS sour crude oil was approximately 60% lower for the first nine months of 2002 than for the same period last year. We believe these narrowed differentials were attributed to OPEC production cutbacks during 2002, which were concentrated in heavy sour and light/medium sour crude oils. This had a significant negative impact on our gross margin because a large proportion of our crude oil throughput is heavy sour and light/medium sour crude oils, which are typically purchased at a discount from WTI, the benchmark crude oil used in industry crack spread calculations. The heavy sour crude oil accounts for between 40% and 45% of our crude oil throughput. Light and medium sour crude oils account for between 21% and 27% of our crude oil throughput. Our gross margin for the first nine months of 2002 was also affected by planned and unplanned downtime at our refineries.

Refinery Operations

In the first nine months of 2002, our Port Arthur refinery experienced crude oil throughput restrictions due to planned turnaround maintenance, unplanned coker repairs, crude supply delays and extreme weather conditions. In the third quarter of 2002, our Port Arthur refinery experienced reduced crude oil throughput rates due to planned delays in crude oil supply resulting from anticipated repairs at the coker unit, which proved to be minimal, and due to unplanned delays in crude oil supply resulting from the impact of production and transportation interruptions caused by hurricanes Isidore and Lili. In the first quarter of 2002, our Port Arthur refinery operations were also affected by the February shutdown of our coker unit for ten days for unplanned maintenance. We took advantage of the coker outage to make repairs to the distillate and naphtha hydrotreaters, including turnaround maintenance that was originally planned for later in the year. Crude oil throughput rates were restricted by approximately 18,000 bpd during this time, but returned to near capacity of 250,000 bpd following the maintenance. In January 2002, we shut down the fluid catalytic cracking (FCC) unit, gas oil hydrotreating unit and sulfur plant for approximately 39 days at our Port Arthur refinery for planned turnaround maintenance. This turnaround maintenance did not affect crude oil throughput rates but did lower gasoline production. We sold more unfinished products during the first quarter of 2002 due to this shutdown.

In the first nine months of 2001, crude oil throughput rates at our Port Arthur refinery were restricted due to a lightning strike in early May and restrictions on the crude unit as downstream process units were in start-up operations during the first quarter. The damage from the lightning strike limited the crude unit rate until the crude unit was shutdown in early July for ten days to repair the damage. Following these repairs, the Port Arthur refinery s crude oil throughput rate was close to capacity for the remainder of the quarter.

In the first nine months of 2002, our Lima refinery operations were affected by an unplanned shutdown of the reformer unit in May. The result of the shutdown was the production of non-saleable inventory that was rerun in the later part of the second quarter and into the third quarter resulting in lost economics. Our Lima refinery had a slightly reduced crude oil throughput rate in the third quarter of 2002 due to delays in crude oil delivery caused by the hurricanes mentioned above. In the first nine months of 2001, crude oil throughput rates were below economic capacity at our Lima refinery due to crude oil delivery delays caused by bad weather in the Gulf Coast and a month-long maintenance turnaround on the coker and isocracker units in the first quarter.

Our Hartford refinery operated below capacity as it reduced inventories as it approached its closure date. The Hartford refinery ceased all crude oil processing operations in late September 2002. Crude oil throughput rates were below capacity for the first nine months of 2001 at our Hartford refinery due to coker unit repairs in the first and third quarters. All three refineries operated below economic crude oil throughput capacity during the first nine months of 2002 due to poor refining market conditions.

We continuously aim to achieve excellent safety and health performance. We believe that a superior safety record is inherently tied to achieving our productivity and financial goals. We measure our success in this area primarily through the use of injury frequency rates administered by the Occupational Safety and Health Administration, or OSHA. The recordable injury rate reflects the number of recordable incidents per 200,000 hours worked, and for the nine months ended September 30, 2002, our refineries had the following recordable injury rates: Port Arthur: 1.39; Lima: 1.59; and Hartford: 0.0. The United States refining industry average recordable injury rate for 2001 was 1.35. Despite our efforts to achieve excellence in our safety and health performance, there can be no assurance that there will not be accidents resulting in injuries or even fatalities.

Operating Expenses. Operating expenses decreased $17.6 million to $338.2 million for the first nine months of 2002 from $355.8 million in the corresponding period in 2001. This decrease was principally due to significantly lower natural gas prices partially offset by higher insurance and employee expenses. The higher insurance expenses related to the overall insurance environment after the events of September 11, 2001, and the higher employee expenses related primarily to new benefit plans and higher medical benefit costs for both current and post retirement plans.

General and Administrative Expenses. General and administrative expenses decreased $4.5 million to $40.8 million in the first nine months of 2002 from $45.3 million in the corresponding period in 2001. This decrease included lower wages and benefits partially offset by relocation costs associated with our new Connecticut office. The lower wages related to a restructuring which resulted in a decrease by approximately one third of the administrative positions in our St. Louis office. The lower benefits principally related to lower incentive compensation under our annual incentive program partially offset by higher costs associated with new pension and retirement plans and both current and post retirement employee medical benefit plans.

Stock Option Compensation Expense. Stock option compensation expense was $9.9 million in the first nine months of 2002. During the second quarter of 2002, we elected to adopt the fair value based expense recognition provisions of SFAS No. 123, Accounting for Stock-Based Compensation (SFAS No. 123). We previously applied the intrinsic value based expense recognition provisions of APB Opinion No. 25, Accounting for Stock Issued to Employees (APB No. 25). SFAS No. 123 provides that the adoption of the fair value based

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method is a change to a preferable method of accounting. As provided by SFAS No. 123, the stock option compensation expense is calculated based only on stock options granted in the year of election and thereafter. All stock options granted prior to January 1, 2002 continue to be accounted for under APB No. 25.

In the period of adoption of SFAS No. 123, the adoption of this fair value based method increased our net loss by $0.6 million (less than $0.01 per basic share) and $0.8 million (less than $0.01 per basic share) for the three-month and six-month periods ended June 30, 2002, respectively. As provided by SFAS No. 123, the first quarter of 2002 was restated to reflect the adoption of SFAS No. 123. For the three months ended March 31, 2002, the effect of the adoption of SFAS No. 123 on loss from continuing operations and net loss to common stockholders was an additional loss of $0.2 million and $0.01 per common share.

Since nonvested awards issued to employees prior to January 1, 2002 continue to be accounted for using the intrinsic value based provisions of APB No. 25, employee stock-based compensation expense determined using the fair value based method applied prospectively is not necessarily indicative of future expense amounts when the fair value based method will apply to all outstanding nonvested awards. With respect to all stock option grants outstanding at September 30, 2002, the Company will record future non-cash stock option compensation expense and additional paid-in capital of $40.4 million over the applicable vesting periods of the grants.

Refinery Restructuring and Other Charges. In 2002, we recorded refinery restructuring and other charges of $172.9 million, which consisted of the following:

- a $137.4 million charge related to the shutdown of refining operations at our Hartford, Illinois refinery,
- a $32.4 million charge related to the restructuring of our management team, refinery operations and administrative functions,
- income of $5.0 million related to the unanticipated sale of a portion of the Blue Island refinery assets previously written off,
- a $2.5 million charge related to the termination of certain guarantees at PACC as part of the Sabine restructuring,
- a $1.4 million loss related to the sale of idled assets, and
- a $4.2 million write-down of our 5% interest in Clark Retail Group, Inc., the sole stockholder of Clark Retail Enterprises, Inc., or CRE. We acquired an interest in Clark Retail Group, Inc. when PRG sold its retail business to CRE in 1999. Clark Retail Group, Inc. and CRE filed a petition to reorganize under Chapter 11 of the U.S. bankruptcy laws in October 2002.

See further details about the Hartford refinery closure and the management, operations and administrative restructuring below.

In 2001, refinery restructuring and other charges of $176.2 million consisted of a $167.2 million charge related to the January 2001 closure of the Blue Island, Illinois refinery and a $9.0 million charge related to the write-off of idled coker units at our Port Arthur refinery. See Factors Affecting Comparability Closure of Blue Island Refinery for additional discussion of the Blue Island charge and reserve. The write-off of idled coker units at our Port Arthur refinery included a charge of $5.8 million related to the net asset value of the coker units and a $3.2 million charge for future environmental clean-up costs related to the coker unit site.

Hartford Refinery Closure

In late September 2002, we ceased refining operations at our Hartford refinery after concluding there was no economically viable method of reconfiguring the refinery to produce fuels meeting new gasoline and diesel fuel specifications mandated by the federal government. Despite ceasing operations, we continue to pursue all strategic options, including expanding the uses of the petroleum product and distribution facility and selling or leasing the refinery, to mitigate the loss of jobs and refinery capacity in the Midwest.

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Since the Hartford refinery operation had been only marginally profitable over the last 10 years and since substantial investment would be required to meet new required product specifications in the future, our reduced refining capacity resulting from the shutdown is not expected to have a significant negative impact on net income or cash flow from operations. The only anticipated effect on net income and cash flow in the future will result from the actual shutdown process, including recovery of realizable asset value, and subsequent environmental site remediation, which we expect will occur over a number of years. Unless there is a need to adjust the shutdown reserve in the future as discussed below, there should be no significant effect on net income beyond 2002.

A pretax charge of $137.4 million was recorded in 2002, which included $70.7 million of non-cash long-lived asset write-offs to reduce the refinery assets to their estimated net realizable value of $61.0 million. The net realizable value was determined by estimating the value of the assets in a sale or operating lease transaction and was recorded as a current asset on our balance sheet. In October 2002, we announced that we would continue to operate the Hartford terminal facility to accommodate our wholesale petroleum product distribution business. As a result, we reclassified the net book value of the terminal assets from assets held for sale to property, plant and equipment. This reduced the estimated net realizable value of the remaining refinery assets to $49.0 million. We have had preliminary discussions with third parties regarding a transaction for the refinery assets, but there can be no assurance that one will be completed. In the event that a sale or lease transaction is not completed, the net realizable value may be less than $49.0 million and a further write-down may be required. In the second quarter of 2002, we completed an evaluation of our warehouse stock, catalysts, chemicals, and additives inventories, and we determined that a portion of these inventories would not be recoverable upon the closure or sale of the refinery. Accordingly, we wrote-down these assets by $3.2 million.

The total charge also included a reserve for future costs of $62.5 million as itemized below. The Hartford restructuring reserve balance and net cash activity as of September 30, 2002 is as follows:

	Initial Reserve	Net Cash Outlay	Reserve as of September 30, 2002
Employee severance	$ 16.6	$ 0.2	$ 16.4
Plant closure/equipment remediation	12.9	5.6	7.3
Site clean-up/environmental matters	33.0		33.0
	$ 62.5	$ 5.8	$ 56.7

Management adopted an exit plan that details the shutdown of the process units at the refinery and the subsequent environmental remediation of the site. We completed the process unit shutdown and hydrocarbon purging in the fourth quarter of 2002. We terminated approximately 300 of 315 employees, both hourly (covered by collective bargaining agreements) and salaried, in October 2002. The remainder of the employees are expected to be terminated within a year. The site clean-up and environmental reserve takes into account costs that are reasonably foreseeable at this time. As the final disposition of the refinery is determined and a site remediation plan refined, further adjustments of the reserve may be necessary, and such adjustments may be material. We expect to spend approximately $20 million to $30 million in 2002 related to employee severance and the process unit shutdown and hydrocarbon purge.

Finally, the total charge included a $1.0 million reserve related to post-retirement benefits that were extended to certain employees who were nearing the retirement requirements. This liability was recorded in Other Long-term Liabilities on the balance sheet together with our other post-retirement liabilities.

Alleged Asbestos Exposure

We, along with numerous other defendants, have recently been named in approximately 22 individual lawsuits alleging personal injury resulting from exposure to asbestos. A majority of the claims have been filed by employees of third-party independent contractors who purportedly were exposed to asbestos while performing services at our Hartford refinery. We have recently been voluntarily dismissed in 17 of the lawsuits in which we have been named. The remainder are in the early stages of litigation. Substantive discovery has not yet been concluded. It is impossible at this time for us to quantify our exposure from these claims, but, based on currently available information, we do not believe that any liability resulting from the resolution of these matters will have a material adverse effect on our consolidated financial position, results of operations or cash flow.

Management, Refinery Operations and Administrative Restructuring

In February 2002, we began the restructuring of our executive management team and subsequently our administrative functions with the hiring of Thomas D. O Malley as chairman, chief executive officer and president and William E. Hantke as executive vice president and chief financial officer. In the first quarter of 2002, as a result of the resignation of the officers who previously held these positions, we recognized severance expense of $5.0 million and non-cash compensation expense of $5.8 million resulting from modifications of stock option terms. In addition, we incurred a charge of $5.0 million for the cancellation of a monitoring agreement with an affiliate of our largest stockholder, Blackstone Management Associates III L.L.C.

In the second quarter of 2002, we commenced a restructuring of our St. Louis-based general and administrative operations and recorded a charge of $6.5 million for severance, outplacement and other restructuring expenses relating to the elimination of 107 hourly and salaried positions. In the third quarter of 2002, we announced plans to reduce our non-represented workforce at our Port Arthur, Texas and Lima, Ohio refineries and make additional staff reductions at our St. Louis administrative office. We recorded a charge of $10.1 million for severance, outplacement, and other restructuring expenses relating to the elimination of 140 hourly and salaried positions. Included in this charge is $1.3 million related to post-retirement benefits that were extended to certain employees who were nearing the retirement requirements. This liability was recorded in Other Long-term Liabilities on the balance sheet together with our other post-retirement liabilities. Reductions at the refineries occurred in October 2002 and those at the St. Louis office will take place by the end of the first quarter of 2003. The reserve related to the refineries and St. Louis restructuring is as follows:

	Initial Reserve	Additional Reserve	Net Cash Outlay	Reserve at September 30, 2002
Refineries and St. Louis restructuring	$ 6.5	$ 8.8	$ 4.6	$ 10.7

We expect to spend approximately $11 million to $13 million in 2002 related to these refinery and St. Louis restructuring activities.

Depreciation and Amortization. Depreciation and amortization expenses decreased $2.8 million to $64.9 million in the first nine months of 2002 from $67.7 million in the corresponding period in 2001. This decrease was principally due to ceasing the recording of depreciation and amortization expense for the Hartford refinery assets beginning in March 2002. This decrease was partially offset by higher amortization expenses at our Lima refinery due to the completion of turnaround activity performed in 2001, and higher amortization at our Port Arthur refinery due to the completion of turnaround activity performed in early 2002.

Interest Expense and Finance Income, net. Interest expense and finance income, net decreased $24.8 million to $81.5 million in the first nine months of 2002 from $106.3 million in the corresponding period in 2001. This decrease related primarily to lower interest expense due to the repurchase of certain debt securities in 2001 and 2002 and lower interest rates on our floating rate debt. The decrease was partially offset by lower interest income as cash balances declined.

Gain or Loss on Extinguishment of Long-term Debt. In the first nine months of 2002, we recorded a loss on extinguishment of long-term debt of $19.5 million related to the redemption of certain long-term debt. This loss included premiums associated with the early repayment of long-term debt of $9.4 million, a write-off of unamortized deferred financing costs related to this debt of $9.5 million, and the write-off of a prepaid premium for an insurance policy guaranteeing the interest and principal payments on Sabine s long-term debt of $0.6 million.

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In the first nine months of 2001, we repurchased in the open market $21.3 million in face value of our 9½% senior notes, $30.6 million in face value of our 10 7/8% senior notes, and $5.9 million in face value of our 11½% exchangeable preferred stock. As a result of these transactions, we recorded a gain of $8.7 million, which included discounts of $9.3 million offset by the write-off of deferred financing costs related to the notes.

Income Tax (Provision) Benefit. We recorded a $99.9 million income tax benefit in the first nine months of 2002 as compared to an income tax provision of $78.7 million in the corresponding period in 2001. The income tax provision of $78.7 million for 2001 included the effect of a $30.0 million decrease in the deferred tax valuation allowance. During the first quarter of 2001, we reversed our remaining deferred tax valuation allowance as a result of the analysis of the likelihood of realizing the future tax benefit of our federal and state tax loss carryforwards, alternative minimum tax credits and federal and state business tax credits.

As of September 30, 2002, we had a net deferred tax asset of $78.8 million recorded on our balance sheet. SFAS No. 109, Accounting for Income Taxes, requires that deferred tax assets be reduced by a valuation allowance if, based on the weight of available evidence, it is more likely than not (a likelihood of more than 50 percent) that some portion or all of the deferred tax assets will not be realized. When applicable a valuation allowance should be recorded to reduce the deferred tax asset to the amount that is more likely than not to be realized. As a result of the analysis of the likelihood of realizing the future tax benefit of our federal and state tax loss carryforwards, alternative minimum tax credits and federal and state business tax credits, we have not provided a valuation allowance related to the net deferred tax asset. The likelihood of realizing the net deferred tax asset is analyzed on a regular basis and should it be determined that it is more likely than not that some portion or all of the net deferred tax asset will not be realized, a tax valuation allowance and a corresponding income tax provision would be required at that time.

Future changes, even slight changes, in the ownership of our common stock (including, among other things, the exercise of compensatory options) could result in an aggregate change in ownership of more than 50% for purposes of Section 382 of the Internal Revenue Code, which could substantially limit the availability of our net operating loss carryforwards, other losses and tax credits.

Discontinued Operations. In 2001, we recorded a pretax charge of $14.0 million, $8.5 million net of income taxes, related to environmental liabilities of discontinued retail operations. This charge represented an increase in estimates regarding our environmental clean up obligation and was prompted by the availability of new information concerning site by site clean up plans and changing postures of state regulatory agencies.

2001 Compared to 2000

Overview. Net income available to common stockholders increased $62.5 million, or 78%, to $142.6 million in 2001 from $80.1 million in 2000. Operating income increased $220.3 million to $367.0 million in 2001 from $146.7 million in 2000. Excluding non-recurring restructuring and other charges of $176.2 million in 2001, operating income increased $396.5 million in 2001 compared to 2000. This increase was principally due to the completion and operation of the heavy oil upgrade project at our Port Arthur refinery, combined with continued strong market conditions.

Net Sales and Operating Revenues. Net sales and operating revenues decreased by $884.2 million, or 12%, to $6,417.5 million in 2001 from $7,301.7 million in 2000. This decrease was principally attributable to steep declines in petroleum product prices in the second half of the year, particularly after the September 11th terrorist attacks, and to our shutdown of the Blue Island, Illinois refinery in January 2001.

Gross Margin. Gross margin increased by $426.9 million, or 58%, to $1,166.1 million in 2001 from $739.2 million in 2000. This increase was principally due to the processing of a greater quantity of less expensive heavy sour crude oil at our Port Arthur refinery, significant discounts on sour and heavy sour crude oil, strong gasoline and distillate market conditions, especially in the first half of the year, as well as solid performance by

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our refineries. These gains were partially offset by poor market conditions in the fourth quarter and plant downtime and operational issues as described below.

The improvement in crude oil discounts was reflected in the increase in the average sour and heavy sour crude oil differentials to West Texas Intermediate. The completion of the heavy oil upgrade project at our Port Arthur refinery has positioned us to maximize the improved crude oil differentials, having processed heavy sour crude oil equal to 43% of total crude oil throughput in 2001 compared to 13% of heavy sour crude oil in 2000. The improved crude oil differentials and the increase in usage of heavy sour crude oil together contributed over $450 million to gross margin in 2001. Margins for light products such as gasoline and distillates remained strong in the first six months of 2001 due to the continued tight supply and demand balance. Industry inventories remained at low levels through most of the first six months of 2001 and were further lowered by industry-wide maintenance turnarounds performed in the first quarter. The improvement in gasoline and distillate margins was reflected by increases in the Gulf Coast and Chicago crack spreads. In the second half of the year, the Gulf Coast and Chicago crack spreads weakened as gasoline and distillate inventory levels increased due to high refinery utilization rates, high import levels, and unseasonably low demand. The lower demand was driven by decreases in air travel after the September 11th terrorist attacks, a weak industrial sector, a general downturn in the economy, and mild winter weather. Due primarily to significant unplanned downtime experienced by other Midwest refiners, the Chicago crack spread did not weaken in proportion to the Gulf Coast crack spread through the third quarter. The Chicago crack spread decreased significantly during the fourth quarter as product was imported into the region due to the higher margins. Overall, crack spreads in 2001 remained above prior year levels.

Excluding the Blue Island refinery s results, our crude oil throughput rate was higher in 2001 as compared to 2000. Overall, our refineries ran well in 2001 with some planned maintenance shutdowns and restrictions and a few unplanned restrictions of our crude and other units. The crude oil throughput rate at our Port Arthur refinery of 229,800 bpd was below capacity of 250,000 bpd in 2001 because units downstream were in start-up operations during the first quarter and a lightning strike in early May 2001 limited the crude unit rate until the crude unit was shut down in early July for ten days to repair the damage caused by the lightning strike. The Port Arthur refinery also experienced a slightly reduced crude oil throughput rate late in the fourth quarter due to minor repairs of the coker and crude units. In March 2001, the Lima refinery performed a planned month-long maintenance turnaround on its coker and isocracker units, and in November 2001 it performed a planned seven-day maintenance turnaround on its crude and other units. The Lima refinery also experienced crude oil supply delays caused by bad weather in the Gulf Coast. Our Hartford refinery experienced ten days of unplanned downtime for coker unit repairs early in the year and planned restricted utilization of the coker unit late in the year due to minor repairs and a shutdown of a third party sulfur plant utilized by Hartford.

Operations in 2000 were affected by the planned month-long maintenance turnaround and subsequent 11-day unscheduled downtime of the Port Arthur refinery crude unit, planned restrictions at all refineries due to weak margin conditions early in the year, unplanned downtime at the Lima refinery due to two electrical outages and a failed compressor, unplanned downtime at the Blue Island refinery requiring maintenance on its vacuum and crude unit, and crude oil supply disruptions to all of the plants late in the year.

Operating Expenses. Operating expenses remained the same at $467.7 million for both 2001 and 2000. Operating expenses benefited significantly in 2001 from the lack of eleven months of operating expenses for the Blue Island refinery in 2001 due to its closure in late January. Offsetting this decrease, however, were higher costs at our Port Arthur refinery for the operation of the new heavy oil processing units, higher energy costs at our Port Arthur refinery, and additional repair and maintenance costs at our Hartford refinery.

General and Administrative Expenses. General and administrative expenses increased $10.3 million, or 19%, to $63.3 million in 2001 from $53.0 million in 2000. This increase was principally due to higher incentive compensation under our annual incentive plan, expenses related to the planning, design and implementation of a new financial and commercial information system, and new support services for the heavy oil processing facility.

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Refinery Restructuring and Other Charges. The refinery restructuring and other charges consisted of a $167.2 million charge related to the January 2001 closure of the Blue Island refinery and a $9.0 million charge related to the write-off of idled coker units at the Port Arthur refinery. See Factors Affecting Comparability Closure of Blue Island Refinery for additional discussion of the Blue Island charge. The write-off of idled coker units at our Port Arthur refinery included a charge of $5.8 million related to the net asset value of the coker units and a $3.2 million charge for future environmental clean-up costs related to the site. We now believe that an alternative use of the coker units is not probable.

Depreciation and Amortization. Depreciation and amortization expenses increased $20.1 million, or 28%, to $91.9 million in 2001 from $71.8 million in the corresponding period in 2000. This increase was principally due to depreciation on the new units associated with the heavy oil upgrade project. We began depreciating these assets in accordance with our property, plant and equipment policy during the first quarter of 2001 following substantial completion of the heavy oil upgrade project and commencement of operations. Amortization contributed to the increase due to a major 2000 Port Arthur refinery turnaround and a first quarter 2001 Lima refinery turnaround.

Interest Expense and Finance Income, net. Interest expense and finance income, net increased by $57.3 million, or 70%, to $139.5 million in 2001 from $82.2 million in 2000. In 2000, the majority of the interest costs on the 12½% senior notes and the senior secured bank loan of our subsidiary, PAFC, were capitalized as part of the heavy oil upgrade project. These costs are now expensed as a result of the commencement of operations in early 2001. Offsetting a portion of this increase were lower interest rates on our floating rate loans.

Gain on Extinguishment of Long-term Debt. In the third quarter of 2001, we repurchased in the open market $21.3 million in face value of our 9½% senior notes, $30.6 million in face value of our 10 $^{7}/8$% senior notes, and $5.9 million in face value of our 11½% exchangeable preferred stock. As a result of these transactions, we recorded a gain of $8.7 million, which included discounts of $9.3 million offset by the write-off of deferred financing costs related to the notes.

Income Tax (Provision) Benefit. The income tax provision increased $78.2 million to $52.4 million in 2001 from a tax benefit of $25.8 million in the corresponding period in 2000. The income tax provision of $52.4 million in 2001 consisted of a provision on income from continuing operations partially offset by the complete reversal of the remaining tax valuation allowance of $30.0 million. The income tax benefit of $25.8 million in 2000 included a reversal of a portion of our tax valuation allowance of $50.8 million partially offset by a provision on income. In September 2001, we made a federal estimated income tax payment of $13.0 million.

Our pretax earnings for financial reporting purposes in the future will generally be fully subject to income taxes, although our actual cash payment of taxes is expected to benefit from regular tax and alternative minimum tax net operating loss carryforwards available at December 31, 2001 of approximately $246 million and $186 million, respectively. Future changes, even slight changes, in the ownership of our common stock (including, among other things, the exercise of compensatory options) could result in an aggregate change in ownership of more than 50% for purposes of Section 382 of the Internal Revenue Code, which could substantially limit the availability of our net operating loss carryforwards, other losses and tax credits.

Discontinued Operations. In 2001, we recorded an additional pretax charge of $29.5 million (net of income taxes $18.0 million) related to the environmental and other liabilities of the discontinued retail operations. See Factors Affecting Comparability Sale of Retail Division for additional discussion of this charge.

2000 Compared to 1999

Overview. Net income available to common stockholders increased by $125.1 million to net income available to common stockholders of 80.1 million in 2000 from a net loss to common stockholders of $45.0 million in 1999. Operating income increased $137.6 million to $146.7 million in 2000 from $9.1 million in 1999.

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Excluding the $105.8 million recovery of a non-cash inventory charge in 1999, operating income increased by $243.4 million in 2000 compared to 1999. This increase was principally due to strong market conditions throughout most of 2000, as evidenced by the change in the Gulf Coast crack spread, which increased from $1.71 per barrel in 1999 to $4.17 per barrel in 2000 and improved sour and heavy sour crude oil differentials.

Net Sales and Operating Revenues. Net sales and operating revenues increased $2,781.2 million, or 62%, to $7,301.7 million in 2000 from $4,520.5 million in 1999. This increase was principally due to higher petroleum prices, as production remained steady. Our average sales price per barrel increased by approximately $14 per barrel for the full year 2000 versus 1999.

Gross Margin. Gross margin increased $318.5 million, or 76%, to $739.2 million in 2000 from $420.7 million in 1999. This increase was principally due to continued strong refined product conditions, particularly for gasoline and distillate margins, and strong operational performance at our refineries in the second half of the year. These significant improvements were partially offset by poor margins on heavier products such as petroleum coke and asphalt due to higher import costs, planned and unplanned downtimes at our refineries, and negative inventory management results.

Market conditions for 2000 started improving over prior year levels during the first quarter and remained above prior year levels for the rest of the year, reaching record levels to date during the second quarter. The main contributor to the higher gross margin was the improvement in gasoline and distillate margins, which were reflected in significant increases in the average Gulf Coast and Chicago crack spreads. We believe these improved market conditions were due mainly to low domestic inventory levels, solid demand, the mandated introduction of a new summer-grade reformulated gasoline, and pipeline supply disruptions. Crude oil discounts for heavier and sour crude oils improved over the prior year, also contributing to gross margin, as evidenced by the improved sour and heavy sour crude oil differentials. These benefits were partially offset by poor heavy product margins as prices for products such as petroleum coke and residual fuel did not track the high feedstock prices in the period.

Major scheduled maintenance turnarounds at our Port Arthur refinery in 2000 and our Lima refinery in 1999 resulted in an opportunity cost from lost production of $30 million in 2000 and $23 million in 1999. In 2000, our Port Arthur refinery crude oil throughput rates were reduced in the first quarter due to problems with the FCC unit, and significantly lowered in the second quarter due to a scheduled turnaround and unscheduled downtime of the crude unit. The work performed during the scheduled turnaround expanded the crude unit capacity from 232,000 bpd to 250,000 bpd and readied the unit to process up to 80% heavy sour crude oil as part of the heavy oil upgrade project. In the third and fourth quarters, the crude oil throughput rate was near its new capacity of 250,000 bpd except for some minor crude oil availability problems in the fourth quarter due to bad weather. Crude oil throughput rates at our Port Arthur refinery were reduced below capacity in 1999 due to poor economic conditions. Crude oil throughput in 2000 was higher than in 1999 at our Lima and Hartford refineries. This was principally because both refineries had solid performance, with only short unplanned downtimes and reduced rates early in 2000 due to poor economic conditions and late in 2000 due to crude oil supply disruptions. Blue Island refinery crude oil throughput rates for 2000 were lower than 1999 due to unplanned downtimes and crude oil supply disruptions.

Our gross margin in 2000 was significantly reduced as a result of negative inventory management results. We incurred losses of approximately $73 million from hedging inventory positions in excess of our target inventory position levels in a backwardated market. Backwardation refers to the time structure of the futures market when the price of a commodity in the current month is higher than the price in the future. This creates an embedded hedging cost as short futures positions are closed, if prices are higher than the hedged price. The inventory position was over target because of the effects of unplanned refinery downtime early in the year, the timing of fixing crude oil price commitments and the fact that, for much of the year, we were hedging to a target inventory level that was not appropriate. The financial effects of inventory management in 1999 were marginally positive.

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Operating Expenses. Operating expenses increased $64.9 million, or approximately 16%, to $467.7 million in 2000 from $402.8 million in 1999. This increase was principally due to higher energy and repair and maintenance costs. The average natural gas price increase of $1.69 per million btu, an increase of 75% over 1999 prices, reflected the increase in energy cost. In addition, our Port Arthur refinery incurred higher repair and maintenance costs in conjunction with the planned turnaround and subsequent unscheduled downtime of its crude unit.

General and Administrative Expenses. General and administrative expenses increased $1.5 million, or approximately 3%, to $53.0 million in 2000 from $51.5 million in 1999. This slight increase was due to higher incentive compensation under our annual incentive plan, offset in part by lower wholesale costs due to the sale of the terminals, the absence of year 2000 systems remediation costs, and the absence of start-up costs related to the initial financing of the heavy oil upgrade project.

Depreciation and Amortization. Depreciation and amortization increased $8.7 million, or approximately 14%, to $71.8 million in 2000 from $63.1 million in 1999. This increase was principally due to the full year impact of a Lima maintenance turnaround performed in 1999 and higher capital expenditures.

Interest Expense and Finance Income, net. Interest expense and finance income, net decreased $9.3 million, or approximately 10%, to $82.2 million in 2000 from $91.5 million in 1999. Of this decrease, $7.6 million related to the absence in 2000 of start-up costs associated with the initial financing of the heavy oil upgrade project. For both 2000 and 1999, the majority of the interest expense from the debt incurred to finance the heavy oil upgrade project was capitalized as part of the project. The remainder of the decrease was due to higher interest income on invested cash balances which more than offset the higher interest expense due to higher interest rates on our $240 million floating rate term loan.

Income Tax Benefit. The income tax benefit increased $13.8 million to $25.8 million in 2000 from $12.0 million in 1999. The income tax benefit of $25.8 million in 2000 represented a decrease in a deferred tax valuation allowance of $50.8 million, partially offset by a provision on income from continuing operations. The income tax benefit of $12.0 million in 1999 reflected the effect of intra-period tax allocations resulting from the utilization of current year operating losses to offset the net income of the discontinued retail division, partially offset by the write-down of a net deferred tax asset.

Discontinued Operations. We reported the results of our retail marketing business that we sold in 1999, which consisted of a loss of $4.3 million, net of an income tax benefit of $2.7 million, and the gain on the sale of the business of $36.9 million, net of income tax provision of $23.7 million, as discontinued operations in 1999.

Outlook

The forward-looking statements made in this Outlook section, as well as any forward-looking statements within other sections of this prospectus, reflect our expectations regarding future events as of the date of the filing of this prospectus, but do not reflect the acquisition of the Memphis refinery. Words such as expects, intends, plans, projects, believes, estimates, will and similar expressions typically identify such forwa statements. Even though we believe our expectations regarding future events are based on reasonable assumptions, forward-looking statements are not guarantees of future performance. For example, set forth in the Refinery Operations section below, we discuss our expectations regarding the performance of our Port Arthur and Lima refineries for the fourth quarter of 2002. Despite our expectations, factors beyond our control such as the reliability and efficiency of our operating facilities, the impact of severe weather, crude oil supply interruptions, and acts of war or terrorism could result in restricted operations, unplanned downtime, and other unanticipated results. See Risk Factors for an expanded list of the factors that could cause actual results to differ materially from our current expectations.

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Market. Crack spreads and crude oil differentials in the fourth quarter of 2002 improved over the results of the prior three quarters. The average Gulf Coast and Chicago crack spreads increased 27% and 36%, respectively, for the fourth quarter of 2002 over the average of the first nine months of 2002. We believe these margins were principally driven by production and transportation interruptions due to hurricanes Isidore and Lili at the beginning of the quarter. Crude oil differentials also improved in the quarter, increasing by approximately 25% for the fourth quarter of 2002 over the average for the first nine months of 2002.

Gross Margin. It is common practice in our industry to look to benchmark market indicators as a predictor of actual refining margins. For example, the 3/2/1 benchmark crack spread models a refinery that consumes WTI sweet crude oil and produces roughly 66% regular gasoline and 33% high sulfur distillate. To improve the reliability of this benchmark as a predictor of actual refining margins, it must first be adjusted for a crude oil slate that is not 100% light and sweet. Secondly, it must be adjusted to reflect variances from the benchmark product slate to the actual, or anticipated, product slate. Lastly, it must be adjusted for any other factors not anticipated in the benchmark, including ancillary crude and product costs such as transportation, storage and credit fees, inventory fluctuations and price risk management activities.

Our Port Arthur refinery has historically produced roughly equal parts gasoline and distillate. For this reason, we believe the Gulf Coast 2/1/1 crack spread more closely reflects our product slate than the Gulf Coast 3/2/1 crack spread. However, approximately 15% of Port Arthur s product slate is lower value petroleum coke and residual oils which will negatively impact the refinery s performance against the benchmark crack spread.

Port Arthur s crude oil slate is approximately 80% Maya heavy sour crude oil and 20% medium sour crude oil. Accordingly, the WTI/Maya and WTI/WTS crude oil differentials can be used as an adjustment to the benchmark crack spread. As discussed elsewhere in this prospectus, we will not receive any discounts on our purchases of Maya crude oil under our long-term crude oil supply agreement through the balance of 2002. Ancillary crude costs, primarily transportation, at Port Arthur averaged $0.95 per barrel of crude oil throughput for the first nine months of 2002. Our reformer unit was down for repairs for approximately two weeks during late October and early November and crude oil throughput rates were restricted during this period. No significant downtime is planned for our Port Arthur refinery for the balance of 2002, and we expect crude oil throughput rates in the fourth quarter of 2002 to continue at, or near, their year-to-date rate in 2002.

Our Lima refinery has a product slate of approximately 60% gasoline and 30% distillate and we believe the Chicago 3/2/1 is an appropriate benchmark crack spread. This refinery consumes approximately 95% light sweet crude oil with the balance being light sour crude oils. We opportunistically buy a mix of domestic and foreign sweet crude oils. The foreign crude oils consumed at Lima are priced relative to Brent and the WTI/Brent differential can be used to adjust the benchmark. Ancillary crude costs for Lima averaged $1.49 per barrel of crude throughput for the first nine months of 2002. In the fourth quarter of 2002, the Lima refinery shutdown its reformer unit for approximately 10 days for repairs, which restricted crude oil throughput rates as well as other unit operations. However, crude oil throughput in the fourth quarter of 2002 is expected to remain at or above year-to-date levels.

Operating Expenses. Natural gas is the most variable component of our operating expenses. On an annual basis, our refineries consume approximately 26.7 million mmbtu of natural gas. Excluding the Hartford refinery, we anticipate this usage will be 21.9 million mmbtu. In a normalized natural gas pricing environment and assuming average crude oil throughput levels, our annual operating expenses should range between $450 million and $475 million. The closure of the Hartford refinery is expected to reduce this amount to between $360 million and $380 million.

General and Administrative Expenses. During 2002, we restructured our general and administrative operations to reduce our overhead costs. As part of these cost reductions we have indefinitely suspended our Senior Executive Retirement Plan, or SERP, and the plan participants have consented to the suspension. In addition, Mr. O Malley has voluntarily agreed to reduce his annual salary by 40% from $500,000 to $300,000.

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Mr. O Malley may reinstate his previous annual salary by giving 30 days notice to us. The SERP may be reinstated with approval of our board of directors. We expect the restructuring to be completed by the end of the first quarter of 2003, and we expect our general and administrative expenses to total approximately $38 million for 2003.

We recognize non-cash, stock option compensation expense computed under SFAS No. 123. As of September 30, 2002, we had incurred $9.9 million in stock option compensation expense for all stock options granted to date in 2002, representing 77% of all stock options currently outstanding. We expect to record approximately $4.2 million per quarter for nine more quarters, reflecting the remaining vesting period for the outstanding 2002 options granted to date. Future stock option grants will be expensed pursuant to the recognition provisions of SFAS No. 123.

Insurance Expense. We carry insurance policies on insurable risks, which we believe to be appropriate at commercially reasonable rates. While we believe that we are adequately insured, future losses could exceed insurance policy limits or, under adverse interpretations, be excluded from coverage. Future costs, if any, incurred under such circumstances would have to be paid out of general corporate funds.

The Company s major insurance policies renewed on October 1, 2002 with a one-year term. Due primarily to the continuing effects of the events of September 11, 2001 on the insurance market, certain coverage terms, including terrorism coverage, were restricted or eliminated at renewal, certain deductibles were raised, certain coverage limits were lowered, and overall premium rates increased by 23%. Higher insurance premium expenses will be reflected in our results beginning in the fourth quarter.

Depreciation and Amortization. Depreciation and amortization expense for the third quarter of 2002 was $20.8 million and excludes the Hartford refinery, which has been accounted for as an asset held for sale. This amount will increase in future periods based upon capital expenditure activity. Included in this amount is the amortization of our turnaround costs, generally over four years.

Interest Expense. Based on our outstanding long-term debt at September 30, 2002, our annual gross interest expense is approximately $85 million. All of our debt is at fixed rates with the exception of $240 million in floating rate notes tied to LIBOR. Reported interest expense is reduced by capitalized interest.

Income Taxes. Our effective tax rate for the nine months ended September 30, 2002 was 37.9% Our effective tax rate for the fourth quarter of 2002 was lower than the rate for the first nine months of the year, primarily due to business tax credits. Our effective tax rate in 2003 should approximate 37% to 38%.

Capital Expenditures and Turnarounds. Capital expenditures and turnarounds for the first nine months of 2002 totaled $97.5 million. We spent $38.1 million in the fourth quarter of 2002 and plan to spend approximately $175 million in 2003. We plan to fund capital expenditures with internally generated funds. However, if the average market environment experienced in the first nine months of 2002 continues, this plan may not be practicable and we are reevaluating the scope and timing of our capital expenditures plan.

Liquidity and Capital Resources

Cash Balances

As of September 30, 2002, we had a cash and short-term investment balance of $158.0 million. In addition, under an amended common security agreement related to PAFC s senior debt, PACC is required to restrict $45.0 million of cash for debt service at all times plus restrict an amount equal to the next scheduled principal and interest payment, prorated based on the number of months remaining until that payment is due. As of September 30, 2002, cash of $51.9 million was restricted under these requirements.

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We maintain a directors and officers insurance policy, which insures our directors and officers from any claim arising out of an alleged wrongful act by such persons in their respective capacities as directors and officers. Pursuant to indemnity agreements between us and each of our directors and officers, we have formed a captive insurance subsidiary, Opus Energy, to provide additional financial coverage for such claims. We have funded an initial $3.0 million and have committed to funding $1 million annually until a loss fund of $10 million is established.

As of December 31, 2001, we had cash, cash equivalents and short-term investments of $511.8 million. Under a common security agreement related to our senior debt at PAFC, PACC s cash of $222.8 million was reserved under a secured account structure for specific operational uses and mandatory debt repayment. The operational uses included various levels of spending, such as current and operational working capital needs, interest and principal payments, taxes, and maintenance and repairs. Cash was applied to each level until that level had been fully funded, upon which the remaining cash flowed to the next level. Once these spending levels were funded, the remaining cash surplus satisfied obligations of a debt service reserve and mandatory debt prepayment with funding occurring semiannually on January 15th and July 15th. On January 15, 2002, PACC used $59.7 million of cash to make a mandatory prepayment of debt under the senior secured bank loan. In addition, as of December 31, 2001, PACC had $30.8 million of cash and cash equivalents restricted for debt service, which included principal of $6.5 million and interest of $24.3 million due in January 2002. These PACC cash restrictions were significantly modified and the secured account structure eliminated in June 2002 under the amended and restated common security agreement due to the Sabine restructuring as explained above.

Cash Flow from Operating Activities

Net cash used in operating activities for the nine months ended September 30, 2002 was $42.2 million compared to net cash provided from operations of $390.2 million in the corresponding period of 2001. The use of cash for operating activities in 2002 as compared to the provision of cash from operations in 2001 is mainly attributable to weak market conditions, which resulted in poor operating results. Working capital as of September 30, 2002 was $291.7 million, a 1.51-to-1 current ratio, versus $482.6 million as of December 31, 2001, a 1.83-to-1 current ratio. The decrease in working capital included the use of approximately $203 million of available cash, excluding initial public offering proceeds, to repay long-term debt. Our cash investment in hydrocarbon working capital at September 30, 2002 remained approximately $50 million above our normalized operating level due primarily to timing of crude oil purchases and product receipts. This incremental investment is believed to be recoverable in the ordinary course of business.

We have increased our reserve for uncollectible accounts receivable to $3.2 million primarily in response to increased risk with respect to our wholesale customers caused by the continued downturn of the U.S. economy.

In 1999, we sold crude oil linefill in the pipeline system supplying the Lima refinery to Koch Supply and Trading L.P. or Koch. As part of the agreement with Koch, we were required to repurchase approximately 2.7 million barrels of crude oil in this pipeline system in September 2002. On October 1, 2002, Morgan Stanley Capital Group Inc., or MSCG, purchased the 2.7 million barrels of crude oil from Koch in lieu of our purchase obligation. We have agreed to purchase those barrels of crude oil from MSCG upon termination of our agreement with them, at then current market prices as adjusted by certain predetermined contract provisions. The initial term of the contract continues until October 1, 2003, and thereafter automatically renews for additional 30-day periods unless terminated by either party. We have hedged the economic price risk related to the repurchase obligation through the purchase of exchange-traded futures contracts.

Clark Retail Group, Inc. and its wholly owned subsidiary, CRE, filed a voluntary petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code on October 15, 2002. As part of PRG s sale of its retail business to CRE in July 1999, PRG assigned approximately 170 leases and subleases of retail stores to CRE. PRG remains jointly and severally liable for CRE s obligations under approximately 150 of those leases, including payment of rent, taxes and environmental cleanup responsibilities for releases of petroleum occurring during the term of the

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leases. Should CRE reject some or all of these leases, PRG may become responsible for these obligations. We are currently evaluating what the financial impact on us will be if PRG is forced to assume liability for the rent and cleanup obligations under a significant number of these leases. Should any of these leases revert to PRG, we will attempt to reduce the potential liability by subletting or reassigning the leases.

Net cash provided by operating activities for the year ended December 31, 2001 was $439.2 million compared to $124.4 million for the year ended December 31, 2000 and $85.5 million for the year ended December 31, 1999. Cash flow from operating activities for the year ended December 31, 2000 and 2001 were mainly impacted by the improvement in cash earnings. Cash flow from operating activities for the year ended December 31, 1999 were mainly impacted by a significant working capital benefit offset by the effects of poor refining margins on cash earnings. Working capital as of December 31, 2001 was $482.6 million, a 1.83:1 current ratio, compared to $325.0 million as of December 31, 2000, a 1.51:1 current ratio.

As of December 31, 2001, our future minimum lease payments under non-cancelable operating leases were as follows (in millions): 2002 $8.0, 2003 $7.4, 2004 $6.0, 2005 $5.7, 2006 $5.3, and $3.6 in the aggregate thereafter.

Cash Flow from Investing Activities

Cash flow used in investing activities for the nine months ended September 30, 2002 were $91.8 million as compared to $98.5 million in the year-earlier period. Activity in both the nine months ended September 30, 2002 and 2001 primarily reflect capital expenditures. We classify our capital expenditures into two main categories, mandatory and discretionary. Mandatory capital expenditures, such as for turnarounds and maintenance, are required to maintain safe and reliable operations or to comply with regulations pertaining to soil, water and air contamination or pollution and occupational, safety and health issues. We estimate that total mandatory capital and turnaround expenditures will average approximately $100 million per year for 2002 through 2006. This estimate includes the capital costs necessary to comply with environmental regulations, except for Tier 2 gasoline standards, on-road diesel regulations and the MACT II regulations described below. Our total mandatory capital and refinery maintenance turnaround expenditure budget, excluding Tier 2 gasoline standards, on-road diesel regulations and the MACT II regulations described below, is approximately $65 million in 2002, of which $56.8 million has been spent as of September 30, 2002. Our total mandatory capital and refinery maintenance turnaround expenditure budget is approximately $85 million for 2003. Discretionary capital expenditures are undertaken by us on a voluntary basis after thorough analytical review and screening of projects based on the expected return on incremental capital employed. Discretionary capital projects generally involve an expansion of existing capacity, improvement in product yields and/or a reduction in operating costs. Accordingly, total discretionary capital expenditures may be less than budget if cash flow is lower than expected and higher than budget if cash flow is better than expected. Our discretionary capital expenditure budget is approximately $30 million in 2002, of which $15.2 million has been spent as of September 30, 2002. Our discretionary capital expenditure budget is approximately $5 million for 2003. We plan to fund both mandatory and discretionary capital expenditures for 2002 with available cash and cash flow from operations.

In addition to mandatory capital expenditures, we expect to incur in the aggregate approximately $545 million through 2006 in order to comply with environmental regulations discussed below. The Environmental Protection Agency, or EPA, has promulgated new regulations under the Clean Air Act that establish stringent sulfur content specifications for gasoline and on-road diesel fuel designed to reduce air emissions from the use of these products.

Tier 2 Motor Vehicle Emission Standards. In February 2000, the EPA promulgated the Tier 2 Motor Vehicle Emission Standards Final Rule for all passenger vehicles, establishing standards for sulfur content in gasoline. These regulations mandate that the average sulfur content of gasoline for highway use produced at any refinery not exceed 30 ppm during any calendar year by January 1, 2006, phasing in beginning on January 1, 2004. We currently expect to produce gasoline under the new sulfur standards at the Port Arthur refinery prior to

January 1, 2004 and, as a result of the corporate pool averaging provisions of the regulations, will not be required to meet the new sulfur standards at the Lima refinery until July 1, 2004, a six month deferral. A further delay in the requirement to meet the new sulfur standards at the Lima refinery through 2005 may be possible through the purchase of sulfur allotments and credits which arise from a refiner producing gasoline with a sulfur content below specified levels prior to the end of 2005, the end of the phase-in period. There is no assurance that sufficient allotments or credits to defer investment at our Lima refinery will be available, or if available, at what cost. We believe, based on current estimates and on a January 1, 2004 compliance date for both the Port Arthur and Lima refineries, that compliance with the new Tier 2 gasoline specifications will require capital expenditures in the aggregate through 2005 of approximately $255 million, an increase of $79 million from 2001 year-end estimates. We have completed detailed engineering studies that have resulted in revised cost estimates based on refined implementation plans. Future revisions to these cost estimates may be necessary. More than 95% of the total investment to meet the Tier 2 gasoline specifications is expected to be incurred during 2002 through 2004 with the greatest concentration of spending occurring in 2003.

Low Sulfur Diesel Standards. In January 2001, the EPA promulgated its on-road diesel regulations, which will require a 97% reduction in the sulfur content of diesel fuel sold for highway use by June 1, 2006, with full compliance by January 1, 2010. Regulations for off-road diesel requirements are pending. We estimate that capital expenditures required to comply with the on-road diesel standards at our Port Arthur and Lima refineries in the aggregate through 2006 is approximately $245 million, an increase of $20 million from previous estimates. The revised estimate is based on additional engineering studies and may be revised further as we move towards finalization of our implementation strategy. More than 95% of the projected investment is expected to be incurred during 2004 through 2006 with the greatest concentration of spending occurring in 2005. Since the Lima refinery does not currently produce diesel fuel to on-road specifications, we are considering an acceleration of the low-sulfur diesel investment at the Lima refinery in order to capture this incremental product value. If the investment is accelerated, production of the low-sulfur fuel is possible by the first quarter of 2005.

Maximum Achievable Control Technology. On April 11, 2002, the EPA promulgated regulations to implement Phase II of the petroleum refinery Maximum Achievable Control Technology rule under the federal Clean Air Act, referred to as MACT II, which regulates emissions of hazardous air pollutants from certain refinery units. We expect to spend approximately $45 million in the next three years related to these new regulations with the greatest concentration of spending evenly spread out over 2003 and 2004. We are performing some tests at our Lima refinery that will determine if we currently meet the MACT II standards. If the tests confirm this compliance then our MACT II spending can be reduced to $25 million. We should know the results of these tests for our year-end 2002 reporting.

Our budget for complying with Tier 2 gasoline standards, on-road diesel regulations and the MACT II regulations is approximately $64 million in 2002, of which $25.5 million has been spent as of September 30, 2002. Our budget for complying with these regulations is approximately $86 million for 2003. It is our intention to fund expenditures necessary to comply with these new environmental standards with cash flow from operations. However, if the average market environment experienced in the first nine months of 2002 continues, it may not be possible for us to generate sufficient cash flow from operations to meet these obligations. Accordingly, we are evaluating our implementation plans.

In conjunction with the work being performed to comply with the above regulations, we have initiated a project to expand the Port Arthur refinery to 300,000 400,000 barrels per day of crude oil throughput capacity. A feasibility study is underway and the ultimate scope and outcome of this project has yet to be determined. We are also evaluating projects to reconfigure the Lima refinery to process a more sour and heavier crude slate. This initiative is in a very preliminary stage.

Cash flow used in investing activities for the year ended December 31, 2001 were $152.9 million as compared to $375.3 million for the year ended December 31, 2000 and $321.3 million for the year ended December 31, 1999. The years ended December 31, 2000 and 1999 reflected higher capital expenditures related

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to the heavy oil upgrade project. Net cash flow provided by investing activities in 1999 included the sale of the retail division for $214.8 million and the sale of the terminals for $33.7 million.

Capital expenditures for the year ended December 31, 2001 were $296.2 million lower than the same period in 2000, principally due to the completion of the construction of the refinery upgrade project. Turnaround costs increased $17.7 million in 2001 due to expenditures in 2001 for planned maintenance at the Port Arthur and Lima refineries while 2000 reflected only the planned maintenance turnaround on the crude unit at Port Arthur. Capital expenditures for property, plant and equipment totaled $94.5 million in 2001, $390.7 million in 2000 and $438.2 million in 1999. Expenditures for property, plant and equipment included $19.0 million, $346.0 million, and $387.6 million in 2001, 2000 and 1999, respectively, related to the Port Arthur heavy oil upgrade project. Expenditures for property, plant and equipment related to mandatory capital expenditures were $37.5 million in 2001, $33.2 million in 2000 and $27.7 million in 1999. Expenditures for refinery maintenance turnarounds totaled $49.2 million in 2001, $31.5 million in 2000 and $77.9 million in 1999, with the Lima refinery undergoing its first major turnaround in 1999 since its acquisition in 1998.

The estimates stated above for future capital expenditures do not include capital expenditure estimates for the Memphis refinery. The sellers of the Memphis refinery estimate that capital expenditures for the refinery will be approximately $80 million for compliance with Tier 2 gasoline standards based on an implementation date of the first quarter of 2004, and approximately $100 million for compliance with low sulfur diesel standards. We do not anticipate the need to spend any capital for MACT II compliance at the Memphis refinery. We also estimate that other mandatory and refinery maintenance turnaround expenditures will be approximately $48 million per year over the next four years for the Memphis refinery.

Cash Flow from Financing Activities

Cash flow used in financing activities were $219.8 million for the nine months ended September 30, 2002 compared to $68.8 million in the prior year for the same period. In 2002, we received total net proceeds, or IPO proceeds, of $482.0 million from the sale of our common stock, which consisted of net proceeds of $462.6 million from an initial public offering of 20.7 million shares of our common stock, $19.1 million from the concurrent sales of 850,000 shares of common stock in the aggregate to Mr. O Malley and two of our directors, and $0.3 million from the exercise of stock options under our stock option plans. The proceeds from the initial public offering and concurrent sales are committed to reducing the long-term debt of our subsidiaries, and as of September 30, 2002 we had contributed a net $442.9 million to our subsidiaries for the early repayment of debt.

In 2002, we redeemed and repurchased portions of our long-term debt totaling $645.2 million in aggregate principal amount. In June 2002, we redeemed the remaining $150.4 million of our 9 $^1/2$% senior notes at par and the remaining $144.4 million of our 10 $^7/8$% senior notes with a $5.2 million premium, all mainly from IPO proceeds.

On April 1, 2002, we exchanged all of our 11 $^1/2$% exchangeable preferred stock for 11 $^1/2$% subordinated debentures. In 2002, we purchased, in the open market, $57.5 million in aggregate principal amount of our 11 $^1/2$% subordinated debentures at a $3.3 million premium from IPO proceeds.

In January 2002, we made a $66.2 million principal payment on our senior secured bank loan with $59.7 million representing a mandatory prepayment pursuant to the common security agreement and secured account structure. In June 2002, we prepaid the remaining balance of $221.4 million on the senior secured bank loan at a $0.9 million premium, with $84.2 million of IPO proceeds and available cash. In the third quarter of 2002, we made a mandatory $4.3 million principal payment on our 12 $^1/2$% senior notes.

Cash and cash equivalents restricted for debt service increased by $21.1 million, of which an increase of $45.2 million related to future principal payments is included in cash flow from financing activity and a decrease of $24.1 million related to future interest payments is included in cash flow from operating activities. The increase in the amount restricted for principal payments mainly reflected the new requirement under the amended and restated common security agreement to maintain a $45.0 million debt service reserve at all times.

In September 2001, we repurchased in the open market $21.3 million in face value of our 9 1/2% senior notes, $30.6 million in face value of our 10 7/8% senior notes, and $5.9 million in face value of our 11 1/2% exchangeable preferred stock, which on April 1, 2002 were converted into 11 1/2% subordinated debentures, for an aggregate purchase price of $48.5 million. We recorded a gain of $8.7 million related to the repurchase of this debt, which included a discount of $9.3 million and a write-off of associated deferred financing costs of $0.6 million.

In 2002, we incurred deferred financing costs of $11.4 million related to the consent process that permitted the Sabine restructuring, the registration of the 12 1/2% senior notes with the Securities and Exchange Commission following the restructuring, and the waiver related to insurance coverage required under the common security agreement.

Cash flow used in financing activities for the year ended December 31, 2001 were $66.3 million as compared to cash flow provided by financing activities of $234.8 million for the year ended December 31, 2000 and $393.9 million for the year ended December 31, 1999. The cash provided by financing activity in 2000 and 1999 included proceeds from our senior secured bank loan, 12 1/2% senior notes, and shareholder contributions received pursuant to capital contribution agreements that were all used to fund the heavy oil upgrade project. There were no similar proceeds in the year ended December 31, 2001.

We have incurred debt at three different entities within our corporate structure: Premcor USA, PRG, and PAFC. Any movement of funds, assets, or other transactions among our various subsidiaries must comply with all provisions of the debt instruments at each subsidiary in addition to customary limitations on transactions with affiliates. After giving effect to this offering and the debt financing and the use of a portion of the proceeds to refinance certain indebtedness of our subsidiaries, as of September 30, 2002, we are required to make the following principal payments on our long-term debt: $0.7 million in the remainder of 2002; $14.9 million in 2003; $25.6 million in 2004; $38.5 million in 2005; $46.4 million in 2006; $318.4 million in 2007; and $601.9 million in the aggregate thereafter. We continue to evaluate the most efficient use of capital and, from time to time, depending upon market conditions, may seek to purchase certain of our outstanding debt securities in the open market or by other means, in each case to the extent permitted by existing covenant restrictions.

As part of the Sabine restructuring, PACC terminated its Winterthur International Insurance Company Limited oil payment guaranty insurance policy, which had guaranteed Maya crude oil purchase obligations made under our long-term agreement with an affiliate of PEMEX. PACC also terminated its $35 million bank working capital facility, which primarily supported non-Maya crude oil purchase obligations. As such, all PACC crude oil purchase obligations are now supported under an amended PRG working capital facility.

PRG has a credit agreement, which provides for the issuance of letters of credit, primarily for the purchases of crude oil, up to the lesser of $650 million or the amount of a borrowing base calculation. In May 2002, PRG amended its $650 million credit agreement to allow for the PACC crude oil purchase obligations. The borrowing base is calculated with respect to our eligible cash and cash equivalents, investments, receivables, petroleum inventories, paid but unexpired letters of credit, and net obligations on swap contracts. Under the amendment, the borrowing base calculation was amended to include PACC inventory. Also as amended, the $650 million limit can be increased by $50 million at the request of PRG upon securing additional commitments. The credit agreement provides for direct cash borrowings up to $50 million. Borrowings under the credit agreement are secured by a lien on substantially all of PRG s cash and cash equivalents, receivables, crude oil and refined product inventories and trademarks. The borrowing base associated with such facility at September 30, 2002 was $797.1 million with $520.2 million of the facility utilized for letters of credit. As of September 30, 2002, there were no direct cash borrowings under the credit agreement.

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The credit agreement contains covenants and conditions that, among other things, limit our dividends, indebtedness, liens, investments and contingent obligations. We are also required to comply with certain financial covenants, including the maintenance of working capital of at least $150 million, the maintenance of tangible net worth of at least $400 million, as amended, and the maintenance of minimum levels of balance sheet cash (as defined therein) of $75 million at all times. The covenants also provide for a cumulative cash flow test that from July 1, 2001 must not be less than zero. In March 2002, we received a waiver regarding the maintenance of the tangible net worth covenant, which allows for the exclusion of $120 million for the pretax restructuring charge related to the closure of the Hartford refinery.

We must amend this credit agreement to extend the maturity date from August 23, 2003 to three years from the closing of the amendment and obtain various waivers and approvals under this credit agreement in order to consummate the debt financing and the acquisition of the Memphis refinery. In addition, we are seeking to amend and restate this credit agreement to, among other things, increase the capacity under the agreement from $650 million to the lesser of $750 million or the amount available under the borrowing base; and increase the sub-limit for cash borrowings from $50 million to $200 million, subject to certain restrictions. Certain covenants relating to minimum cash requirements, permitted indebtedness and minimum net worth requirements will also be modified. There are no assurances that we will be able to obtain the necessary extension, waivers and approvals or enter into an amended and restated credit agreement on these terms or at all.

Our long-term debt instruments subject us to significant financial and other restrictive covenants. Covenants contained in various indentures, credit agreements, and term loan agreements place restrictions on, among other things, our subsidiaries ability to incur additional indebtedness, place liens upon our subsidiaries assets, pay dividends or make certain other restricted payments and investments. Some debt instruments also require our subsidiaries to satisfy or maintain certain financial condition tests.

Funds generated from operating activities together with existing cash, cash equivalents and short-term investments and proceeds from asset sales are expected to be adequate to fund existing requirements for working capital and capital expenditure programs for the next year. Due to the commodity nature of our products, our operating results are subject to rapid and wide fluctuations. While we believe that our operating philosophies will be sufficient to provide us with adequate liquidity through the next year, there can be no assurance that market conditions will not be worse than anticipated. Future working capital, discretionary capital expenditures, environmentally mandated spending and acquisitions may require additional debt or equity capital.

Accounting Standards

Critical Accounting Standards

Contingencies. We account for contingencies in accordance with the Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards No. 5 (SFAS No.5), *Accounting for Contingencies*. SFAS No. 5 requires that we record an estimated loss from a loss contingency when information available prior to the issuance of our financial statements indicates that it is probable that an asset has been impaired or a liability has been incurred at the date of the financial statements and the amount of the loss can be reasonably estimated. Accounting for contingencies such as environmental, legal and income tax matters require us to use our judgment. While we believe that our accruals for these matters are adequate, if the actual loss from a loss contingency is significantly different than the estimated loss, our results of operations may be over or understated.

Major Maintenance Turnarounds. The Accounting Standards Executive Committee of the American Institute of Certified Public Accountants, or AcSEC, had issued an exposure draft of a proposed statement of position, or SOP, entitled *Accounting for Certain Costs and Activities Related to Property, Plant and Equipment*. If adopted as proposed, this SOP would have, among other things, required companies to expense as incurred turnaround costs, which it terms as the non-capital portion of major maintenance costs. Adoption of the proposed SOP would have also required that any existing unamortized turnaround costs be expensed immediately. As of September 30, 2002, we had approximately $97 million in unamortized turnaround costs on our balance sheet. A turnaround is a periodically required standard procedure for maintenance of a refinery that involves the shutdown and inspection of major processing units and generally occurs every three to five years. Turnaround costs include actual direct and contract labor, and material costs for the overhaul, inspection, and replacement of major components of refinery processing and support units performed during the turnaround. We currently amortize turnaround costs, which are included in our consolidated balance sheets in Other Assets, on a straight-line basis over the period until the next scheduled turnaround, beginning the month following completion. The amortization of turnaround costs is presented as Amortization on our consolidated statements of operations.

In December 2002, AcSEC discontinued discussions concerning this SOP and handed over the responsibility for any further action to the FASB. The FASB stated that it might add the issues related to this SOP to its agenda, but it would be at least 12 months until any consideration is made. At its January 2003 meeting, AcSEC agreed to meet with the FASB to discuss the possibility of adopting a shortened version of the original exposure draft that would address major maintenance costs or turnaround costs. Whether there will be new accounting guidance and when it would become effective is currently unclear.

Impairment of Long-Lived Assets. In August 2001, the FASB issued SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. This statement addresses financial accounting and reporting for the impairment or disposal of long-lived assets and supersedes SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of*, and the accounting and reporting provisions of Accounting Principles Board Opinion No. 30, *Reporting the Results of Operations-Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions*, for the disposal of a segment of a business (as previously defined in that Opinion). The provisions of this statement are effective for financial statements issued for fiscal years beginning after December 15, 2001 and interim periods within those fiscal years, with early application encouraged. The implementation of SFAS 144 did not have a material impact on our financial position or results of operations.

Inventories. Inventories for our company are stated at the lower of cost or market. As of January 1, 2002, cost is determined under the LIFO method for hydrocarbon inventories including crude oil, refined products, and blendstocks. Prior to this date the cost of Sabine s hydrocarbon inventories was determined under the first-in, first-out, or FIFO, method. The cost of warehouse stock and other non-hydrocarbon inventories is determined under the FIFO method. Any reserve for inventory cost in excess of market value is reversed if physical inventories turn and prices recover above cost. At December 31, 2001 the replacement cost (market value) of our crude oil and refined product inventories exceeded its carrying value by $4.9 million. We had 15.4 million barrels of crude oil and refined product inventories at December 31, 2001 with an average cost of $19.09 per barrel. If the market value of these inventories had been lower by $1 per barrel at December 31, 2001, we would have been required to write-down the value of our inventory by $10.5 million. If prices decline from year-end 2001 levels, we may be required to write-down the value of our inventories in future periods.

New Accounting Standards

On January 1, 2002, we adopted Statement of Financial Accounting Standard, or SFAS, No. 142, *Goodwill and Other Intangible Assets,* and SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.* The adoption of these standards did not have a material impact on our financial position and results of operations; however, SFAS No. 144 was utilized in the accounting for our announced intention to discontinue refining operations at the Hartford, Illinois refinery.

In July 2001, the Financial Accounting Standards Board, or FASB, approved SFAS No. 143, *Accounting for Asset Retirement Obligations.* SFAS No. 143 addresses when a liability should be recorded for asset retirement obligations and how to measure this liability. The initial recording of a liability for an asset retirement obligation will require the recording of a corresponding asset that will be required to be amortized. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. We are in the process of evaluating the impact of the adoption of this standard on our financial position and results of operations and believe implementation will not have a material impact.

In April 2002, the FASB issued SFAS No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13 and Technical Corrections*. SFAS 145 rescinds SFAS No. 4, *Reporting Gains and Losses from the Extinguishment of Debt*; SFAS No. 44, *Accounting for Intangible Assets of Motor Carriers*; and SFAS No. 64, *Extinguishment of Debt Made to Satisfy Sinking-Fund Requirements*. SFAS No. 145 also amends SFAS No. 13, *Accounting for Leases*, as it relates to sale-leaseback transactions and other transactions structured similar to a sale-leaseback as well as amends other pronouncements to make various technical corrections. The provisions of SFAS No. 145 as they relate to the rescission of SFAS No. 4 shall be applied in fiscal years beginning after May 15, 2002. The provision of this statement related to the amendment to SFAS No. 13 shall be effective for transactions occurring after May 15, 2002. All other provisions of this statement shall be effective for financial statements on or after May 15, 2002. As permitted by the statement, we have elected early adoption of SFAS 145 and, accordingly, have included any gains or losses on extinguishment of debt in Income from continuing operations as opposed to as an extraordinary item, net of taxes, below Income from continuing operations in our Statement of Operations.

In June 2002, the FASB issued SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*. SFAS No. 146 requires the recognition of liabilities at fair value that are associated with exit or disposal activities when they are incurred rather than at the date of a commitment to an exit or disposal plan. Such liabilities include lease termination costs and certain employee severance costs that are associated with a restructuring, discontinued operation, plant closing or other exit or disposal activities. SFAS No. 146 is to be applied prospectively to exit or disposal activities initiated after December 31, 2002. We will adopt SFAS No. 146 for all restructuring, discontinued operations, plant closings or other exit or disposal activities initiated after December 31, 2002.

Quantitative and Qualitative Disclosures About Market Risk

The risk inherent in our market risk sensitive instruments and positions is the potential loss from adverse changes in commodity prices and interest rates. None of our market risk sensitive instruments is held for trading.

Commodity Risk

Our earnings, cash flow and liquidity are significantly affected by a variety of factors beyond our control, including the supply of, and demand for, commodities such as crude oil, gasoline and other refined products. The demand for these refined products depends on, among other factors, changes in domestic and foreign economies, weather conditions, domestic and foreign political affairs, planned and unplanned downtime in refineries, pipelines and production facilities, production levels, the availability of imports, the marketing of competitive fuels and the extent of government regulation. As a result, crude oil and refined product prices fluctuate significantly, which directly impacts our net sales and operating revenues and costs of goods sold.

The movement in petroleum prices does not necessarily have a direct long-term relationship to net income. The effect of changes in crude oil prices on our operating results is determined more by the rate at which the prices of refined products adjust to reflect such changes. We are required to fix the price on our crude oil purchases approximately two to three weeks prior to the time when the crude oil can be processed and sold. As a result, we are exposed to crude oil price movements relative to refined product price movements during this period. In addition, earnings may be impacted by the write-down of our inventory cost to market value when market prices drop dramatically compared to our inventory cost. These potential write-downs may be recovered in subsequent periods as our inventories turn and market prices rise. If prices decline dramatically near the end of a period, we may be required to write-down the value of our inventories in future periods. In 1997 and 1998 the

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market value of our petroleum inventory was below original cost, which resulted in a write-down of inventory to fair market value. The write-down was fully recovered in 1999 when market values increased. Earnings may continue to be impacted by these write-downs, or recovery of write-downs, to market value.

As of December 31, 2001, we had 15.4 million barrels of crude oil and refined product inventories. We had 12.6 million barrels of crude oil and refined product inventories that were valued under the LIFO inventory method with an average cost of $20.32 per barrel. As of December 31, 2001, the replacement cost (market value) of this inventory exceeded its carrying value by $4.9 million. If the market value of these inventories had been lower by $1 per barrel as of December 31, 2001, we would have been required to write-down the value of our inventory by $7.7 million. We had 2.8 million barrels of crude oil and refined product inventories that were valued under the first-in, first-out, or FIFO, inventory method with an average cost of $13.58 per barrel. The carrying value of this inventory approximated replacement cost (market value). If the market value of these inventories had been lower by $1 per barrel we would have been required to write-down the value of our inventory by $2.8 million.

As of December 31, 2000, we had 18.0 million barrels of crude oil and refined product inventories. We had 15.6 million barrels of crude oil and refined product inventories that were valued under the LIFO inventory method with an average cost of $19.94 per barrel. The replacement cost (market value) of this inventory exceeded its carrying value by $100.8 million. If the market value of these inventories had been lower by $1 per barrel as of December 31, 2000, we would not have been required to write-down the value of our inventory and would not have had to record a write-down unless market was lower by over $7 per barrel. We had 2.4 million barrels of crude oil and refined product inventories that were valued under the FIFO inventory method with an average cost of $18.38 per barrel. If the market value of these inventories had been lower by $1 per barrel we would have been required to write-down the value of our inventory by $2.4 million.

As of January 1, 2002, all of our hydrocarbon inventories were valued using the LIFO method. Our inventories that are valued under the LIFO method are more susceptible to a material write-down when prices decline dramatically. If prices decline from year-end 2001 levels, we may be required to write-down the value of our LIFO inventories in future periods.

The nature of our business leads us to maintain a substantial investment in petroleum inventories. Since petroleum feedstocks and products are essentially commodities, we have no control over the changing market value of our investment. We manage the impact of commodity price volatility on our hydrocarbon inventory position by, among other methods, determining a volumetric exposure level that we consider appropriate and consistent with normal business operations. This target inventory position includes both titled inventory and fixed price purchase and sale commitments. The portion of our current target inventory position consisting of sales commitments netted against fixed price purchase commitments amounts to a net long inventory position of approximately 4 million barrels.

Prior to the second quarter of 2002, we did not generally price protect any portion of our target inventory position. However, although we continue to generally leave the titled portion of our inventory position target fully exposed to price fluctuations, beginning in the second quarter of 2002, we began to actively mitigate some or all of the price risk related to our target level of fixed price purchase and sale commitments. These risk management decisions are based on the relative level of absolute hydrocarbon prices. The cumulative economic effect of our risk management strategy in the second and third quarter of 2002 resulted in an approximate $11 million loss as measured against a fully exposed fixed price commitment target. In the first quarter of 2002, we benefited by approximately $30 million from having our fixed price commitment target fully exposed in a rising absolute price environment.

We use several strategies to minimize the impact on profitability of volatility in feedstock costs and refined product prices. These strategies generally involve the purchase and sale of exchange-traded, energy-related futures and options with a duration of six months or less. To a lesser extent we use energy swap agreements

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similar to those traded on the exchanges, such as crack spreads and crude oil options, to better match the specific price movements in our markets as opposed to the delivery point of the exchange-traded contract. These strategies are designed to minimize, on a short-term basis, our exposure to the risk of fluctuations in crude oil prices and refined product margins. The number of barrels of crude oil and refined products covered by such contracts varies from time to time. Such purchases and sales are closely managed and subject to internally established risk standards. The results of these price risk mitigation activities affect refining cost of sales and inventory costs. We do not engage in speculative futures or derivative transactions.

We prepared a sensitivity analysis to estimate our exposure to market risk associated with derivative commodity positions. This analysis may differ from actual results. The fair value of each derivative commodity position was based on quoted futures prices. As of September 30, 2002, a 10% change in quoted futures prices would result in an $8.8 million change to the fair market value of the derivative commodity position and correspondingly the same change in operating income. As of December 31, 2001, a 10% change in quoted futures prices would result in an $8.1 million change to the fair market value of the derivative commodity position and correspondingly the same change in operating income.

Interest Rate Risk

During 2002, as of September 30, we repaid $645.2 million of our long-term debt, leaving an outstanding balance, including current maturities, of $925.3 million at September 30, 2002. Our primary interest rate risk is associated with our long-term debt. We manage this interest rate risk by maintaining a high percentage of our long-term debt with fixed rates. The weighted average interest rate on our fixed rate long-term debt is slightly over 10%. We are subject to interest rate risk on our floating rate loans and any direct borrowings under our credit facility. As of September 30, 2002, a 1% change in interest rates on our floating rate loans, which totaled $250 million, would result in a $2.5 million change in pretax income on an annual basis. As of December 31, 2001, a 1% change in interest rate on our floating rate loans, which totaled $538 million, would result in a $5.4 million change in pretax income on an annual basis. As of September 30, 2002 and December 31, 2001, there were no borrowings under our credit agreement.

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INDUSTRY OVERVIEW

Oil refining is the process of separating hydrocarbon atoms present in crude oil and converting them into usable finished petroleum products. There are approximately 150 oil refineries operating in the United States. The refining industry is characterized by capacity shortage, high utilization, and reliance on imported products to meet demand for finished petroleum products. This overview explains the basics of the refining process and certain factors that influence our industry.

Refining Basics

Refineries are uniquely designed to process specific crude oils into selected products. In general, the different process units inside a refinery perform one of three functions:

- separate the many types of hydrocarbons present in crude oil;
- chemically convert the separated hydrocarbons into more desirable products; and
- treat the products by removing unwanted elements and compounds.

Each step in the refining process is designed to maximize the value of the feedstocks, particularly the raw crude oil.

The first refinery units to process raw crude oil are typically the atmospheric and vacuum distillation units. Crude oil is separated by boiling point in the distillation units under high heat and low pressure and recovered as hydrocarbon fractions. The lowest boiling fractions, including gasoline and liquefied petroleum gas, vaporize and exit the top of the atmospheric distillation unit. Medium boiling liquids, including jet fuel, kerosene and distillates such as home heating oil and diesel fuel, are drawn from the middle. Higher boiling liquids, called gas oils and the highest boiling liquids, called residuum, are drawn together from the bottom and separated in the vacuum distillation unit. The various fractions are then pumped to the next appropriate unit in the refinery for further processing into higher-value products.

The next step in the refining process is to convert the hydrocarbon fractions into distinct products. One of the ways of accomplishing this is through cracking, a process that breaks or cracks higher boiling fractions into more valuable products such as gasoline, distillate and gas oil. The most important conversion units are the coker, the FCC unit, and the hydrocracker. Thermal cracking is accomplished in the coker, which upgrades residuum into naphtha, which is a low-octane gasoline fraction, distillate, and gas oil. The FCC unit converts gas oil from the crude distillation units and coker into liquefied petroleum gas, gasoline, and distillate by applying heat in the presence of a catalyst. The hydrocracker receives feedstocks from the coker, FCC and crude distillation units. This unit converts lower value intermediate products into gasoline, naphtha, kerosene, and distillates under very high pressure in the presence of hydrogen and a catalyst.

Finally, the intermediate products from the distillation and conversion processes are treated to remove impurities such as sulfur, nitrogen and heavy metals, and are processed to enhance octane, reduce vapor pressure, and meet other product specifications. Treatment is accomplished in hydrotreating units by heating the intermediates under high pressure in the presence of hydrogen and catalysts. Octane enhancement is accomplished primarily in a reformer. The reformer converts naphtha, or low-octane gasoline fractions, into higher octane gasoline blendstocks used in increasing the overall octane level of the gasoline pool. Vapor pressure reduction is accomplished primarily in an alkylation unit. The alkylation unit decreases the vapor pressure of gasoline blendstocks produced by the FCC and coker units through the conversion of light olefins to heavier, high-octane paraffins.

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Refinery Products

Major refinery products include:

Gasoline. The most significant refinery product is motor gasoline. Various gasoline blendstocks are blended to achieve specifications for regular and premium grades in both summer and winter gasoline formulations. Refiners must also produce many grades of reformulated gasoline. Reformulated gasolines are special blends containing oxygenates, such as ethers or alcohols, that are tailored to areas of the country with severe ozone pollution. Additives are often used to enhance performance and provide protection against oxidation and rust formation.

Distillate Fuels. Distillates are diesel fuels and domestic heating oils.

Kerosene. Kerosene is a refined middle-distillate petroleum product that is used for jet fuel, cooking and space heating, lighting, solvents and for blending into diesel fuel.

Petrochemicals. Many products derived from crude oil refining, such as ethylene, propylene, butylene and isobutylene, are primarily intended for use as petrochemical feedstock in the production of plastics, synthetic fibers, synthetic rubbers and other products. A variety of products are produced for use as solvents, including benzene, toluene and xylene.

Liquefied Petroleum Gas. Liquefied petroleum gases, consisting primarily of propane and butane, are produced for use as a fuel and an intermediate material in the manufacture of petrochemicals.

Residual Fuels. Many marine vessels, power plants, commercial buildings and industrial facilities use residual fuels or combinations of residual and distillate fuels for heating and processing. Asphalts are also made from residual fuels and are used primarily for roads and roofing materials.

Petroleum Coke. Petroleum coke, a by-product of the coking process, is almost pure carbon and has a variety of uses. Fuel grade coke is used primarily by power plants as fuel for producing electricity. Premium grades of coke low in sulfur and metal content are used as anodes for the manufacture of aluminum.

Crude Oil

The quality of crude oil dictates the level of processing and conversion necessary to achieve the optimal mix of finished products. Crude oils are classified by their density (light to heavy) and sulfur content (sweet to sour). Light sweet crude oils are more expensive than heavy sour crude oils because they require less treatment and produce a slate of products with a greater percentage of high-priced, light, refined products such as gasoline, kerosene and jet fuel. The heavy sour crude oils typically sell at a discount to the lighter, sweet crude oils because they produce a greater percentage of lower-value products with simple distillation and require additional processing to produce the higher-value light products. Consequently, refiners strive to process the optimal mix, or slate, of crude oils through their refineries, depending on each refinery s conversion and treating equipment, the desired product output, and the relative price of available crude oils.

Refinery Complexity

Refinery complexity refers to a refinery s ability to process less-expensive feedstock, such as heavier and higher-sulfur content crude oils, into value-added products. Generally, the higher the complexity and more flexible the feedstock slate, the better positioned the refinery is to take advantage of the more cost-effective crude oils, resulting in incremental gross margin opportunities for the refinery.

Refinery Locations

A refinery s location can have an important impact on its refining margins since a refinery s location can influence its ability to access feedstocks and distribute its products efficiently. There are five regions in the

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United States, as defined by the Petroleum Administration for Defense Districts, or PADDs, that have historically experienced varying levels of refining profitability due to regional market conditions. For example, refiners located in the Gulf Coast operate in a highly competitive market due to the fact that this region (PADD III) accounts for approximately 37% of the total number of United States refineries and approximately 46% of the country s refining capacity. Alternatively, demand for gasoline and distillates has historically exceeded refining production by approximately 35% in the Midwest (PADD II). PADD I represents the East Coast, PADD IV the Rocky Mountains and PADD V is the West Coast.

Structure of Refining Companies

Refiners typically are structured as part of an integrated oil company or as an independent entity. Integrated oil companies have upstream operations, which are concerned with the exploration and production of crude oil, combined with downstream, or refining, operations. An independent refiner has no source of proprietary crude oil production.

Refiners primarily distribute their products as either wholesalers or retailers. Refiners who operate as wholesalers principally sell their refined products under spot and term contracts to bulk and truck rack customers. Wholesalers who sell their products on an unbranded basis are called merchant refiners. Many refiners, both integrated and independent, distribute their refined products through their own retail outlets.

Economics of Refining

Refining is primarily a margin-based business where both the feedstocks and refined finished products are commodities. Because operating expenses are relatively fixed, the refiners goal is to maximize the yields of high-value products and to minimize feedstock costs.

The industry uses a number of benchmarks to measure market values and margins:

West Texas Intermediate. In the United States, West Texas Intermediate crude oil is the reference quality crude oil. West Texas Intermediate is a light sweet crude oil and the West Texas Intermediate benchmark is used in both the spot and futures markets.

3/2/1 crack spread. Crack spreads are a proxy for refining margins and refer to the margin that would accrue from the simultaneous purchase of crude oil and the sale of refined petroleum products, in each case at the then prevailing price. The 3/2/1 crack spread assumes three barrels of West Texas Intermediate crude oil will produce two barrels of regular unleaded gasoline and one barrel of high-sulfur diesel fuel. Average 3/2/1 crack spreads vary from region to region depending on the supply and demand balances of crude oils and refined products.

Actual refinery margins vary from the 3/2/1 crack spread due to the actual crude oil used and products produced, transportation costs, regional differences, and the timing of the purchase of the feedstock and sale of the light products.

High complexity refineries are able to utilize crude oils lower in cost than West Texas Intermediate. The economic advantage of these refineries is estimated by using the heavy/light and the sweet/sour differentials.

Heavy/light differential. The heavy/light differential is the price differential between Maya, a heavy, sour crude oil, and West Texas Intermediate crude oil. Maya crude oil typically trades at a discount to West Texas Intermediate crude oil.

Sweet/sour differential. The sweet/sour differential is the price differential between West Texas Sour, a medium sour crude oil and West Texas Intermediate crude oil. West Texas Sour crude oil trades at a discount to West Texas Intermediate crude oil. Typically, the sweet/sour differential is less than the heavy/light differential.

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Product differentials. Because refineries produce many other products that are not reflected in the crack spread, product differentials to regular unleaded gasoline and high-sulfur diesel are calculated to analyze the product mix advantage of a given refinery. Those refineries that produce relatively high volumes of premium products such as premium and reformulated gasoline, low-sulfur diesel fuel and jet fuel and relatively low volumes of by-products such as liquefied petroleum gas, residual fuel oil, petroleum coke, and sulfur have an economic advantage.

Operating expenses. Major operating costs include employee labor, repairs and maintenance, and energy. Employee labor and repairs and maintenance are relatively fixed costs that generally increase proportional to inflation. By far, the predominant variable cost is energy and the most reliable price indicator for energy costs is the cost of natural gas.

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BUSINESS

Overview

We are one of the largest independent petroleum refiners and suppliers of unbranded transportation fuels, heating oil, petrochemical feedstocks, petroleum coke and other petroleum products in the United States. We currently own and operate two refineries in Port Arthur, Texas and Lima, Ohio with a combined crude oil throughput capacity of approximately 420,000 bpd. In late September 2002, we ceased refining operations at our Hartford, Illinois refinery and are currently pursuing all strategic options, including expanding the uses of the petroleum product and distribution facility and selling or leasing the refinery, to mitigate the loss of jobs and refinery capacity in the Midwest. We continue to operate the terminal facility at the Hartford refinery to accommodate our wholesale petroleum product distribution business. We sell petroleum products in the Midwest, the Gulf Coast, eastern and southeastern United States. We sell our products on an unbranded basis to approximately 750 distributors and chain retailers through our own product distribution system and an extensive third-party owned product distribution system, as well as in the spot market.

For the nine months ended September 30, 2002, light products accounted for approximately 90% of our total product volume. For the same period, high-value, premium product grades, such as high octane and reformulated gasoline, low-sulfur diesel and jet fuel, which are the most valuable types of light products, accounted for approximately 40% of our total product volume.

We source our crude oil on a global basis through a combination of long-term crude oil purchase contracts, short-term purchase contracts and spot market purchases. The long-term contracts provide us with a steady supply of crude oil, while the short-term contracts and spot market purchases give us flexibility in obtaining crude oil. Since all of our refineries have access, either directly or through pipeline connections, to deepwater terminals, we have the flexibility to purchase foreign crude oils via waterborne delivery or domestic crude oils via pipeline delivery. Our Port Arthur refinery, which possesses one of the world s largest coking units, can process 80% heavy sour crude oil. Approximately 80% of the crude oil supply to our Port Arthur refinery is lower cost heavy sour crude oil from Mexico, called Maya, most of which benefits from a mechanism intended to provide us with a minimum average coker gross margin and moderate fluctuations in coker gross margins during an eight-year period beginning on April 1, 2001.

Recent Developments

Memphis Refinery Acquisition

On November 25, 2002, we announced that we had executed a definitive agreement with The Williams Companies, Inc. and certain of its subsidiaries to purchase their Memphis, Tennessee refinery and related supply and distribution assets. The purchase price for the refinery and the other assets is $315 million plus the value of inventories at closing, which were estimated to be $150 million at the time of the agreement. The agreement also provides for contingent participation, or earn-out, payments that could result in additional payments of up to $75 million by us to Williams over the next seven years, depending on the level of industry refining margins during that period.

The Memphis refinery has a rated crude oil throughput capacity of 190,000 bpd but typically processes approximately 170,000 bpd. The related assets include two truck-loading racks; three petroleum terminals in the area; supporting pipeline infrastructure that transports both crude oil and refined products; crude oil tankage at St. James, Louisiana; and an 80 megawatt power plant adjacent to the refinery.

We believe that we are acquiring a quality refinery at an attractive price that will produce operating and economic synergies and that should be accretive to our earnings per share and generate positive cash flow from operations. Completion of the acquisition is subject to our obtaining the requisite financing and the satisfaction of customary conditions, including regulatory approvals. We intend to finance the acquisition from the proceeds of this offering and the other financing transactions. We expect the acquisition to close during the first quarter of 2003.

Our Predecessors and Corporate Structure

Clark USA, Inc., our predecessor, was formed by TrizecHahn Corporation, or TrizecHahn, in 1988 to acquire a controlling interest in certain refining, distribution and marketing assets from the bankruptcy estate of Clark Oil & Refining Corporation. Those assets, which included the Hartford refinery, a Blue Island, Illinois refinery and certain Clark USA retail operations and product terminals, were acquired by Clark Refining & Marketing, Inc., a wholly owned subsidiary of Clark USA. In November 1997, Blackstone acquired a majority interest in Clark USA from TrizecHahn. In 1999, we were formed as Clark Refining Holdings, Inc., a holding company for 100% of the capital stock of Clark USA. In 2000, we changed our name to Premcor Inc., Clark USA changed its name to Premcor USA Inc. and Clark Refining & Marketing, Inc., one of our operating subsidiaries, changed its name to The Premcor Refining Group Inc.

In 1999, in connection with the financing of the heavy oil upgrade project at our Port Arthur refinery, we acquired 90% of the capital stock of Sabine River Holding Corp., a new entity formed to be the general partner of PACC, the entity created to own and lease the assets comprising the heavy oil processing facility. Sabine also owns 100% of the capital stock of Neches River Holding Corp., which was formed to be the 99% limited partner of PACC. PACC entered into product purchase, service and supply agreements and facility, site and ground leases, and other arm s length arrangements with PRG as part of the heavy oil upgrade project.

In connection with the Sabine restructuring, on June 6, 2002, we consummated a share exchange with Occidental Petroleum Corporation whereby we received the remaining 10% of the common stock of Sabine. For a discussion of our relationship with Occidental, see Related Party Transactions Our Relationship with Occidental. Upon consummation of the share exchange with Occidental, we contributed our ownership interest in Sabine to PRG and Sabine became a direct, wholly owned subsidiary of PRG.

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The following chart summarizes the current corporate structure of Premcor Inc. and its affiliates as a result of the Sabine restructuring:

The Transformation of Premcor

Beginning in early 1995 and continuing after Blackstone acquired its controlling interest in our predecessor in 1997, we completed several strategic initiatives that have significantly enhanced our competitive position, the quality of our assets, and our financial and operating performance. The following statements regarding our transformation exclude our Hartford refinery at which we ceased refining operations in late September 2002. For example, we:

Divested our Non-core Assets to Focus on Refining. We divested our non-core assets during 1998 and 1999, generating net proceeds of approximately $325 million, which we reinvested into our refining business. In 1998, we sold minority interests in several crude oil and product pipelines. In July 1999, we sold our retail business, which included 672 company-operated, and over 200 franchised, gas convenience stores. Also in 1999, we sold the majority of our product distribution terminals.

Acquired Additional Competitive Refining Capacity. We increased our net crude oil throughput capacity from approximately 130,000 bpd to 420,000 bpd after closing two refineries by acquiring our Lima and Port Arthur refineries and subsequently upgrading our Port Arthur refinery. In 1995, we significantly changed the character of our asset base by acquiring the Port Arthur refinery, which was then operating at a capacity of 178,000 bpd. In August 1998, we further expanded our refining capacity by acquiring the 170,000 bpd Lima refinery.

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Invested in Improving the Productivity of our Asset Base. We implemented capital projects to increase throughput and premium product yields and to reduce operating expenses within our refining asset base. Upon the acquisition of our Port Arthur refinery in 1995, we initially upgraded the facility to a capacity of 232,000 bpd. In January 2001, we completed construction and commenced operation of a heavy oil upgrade project at Port Arthur, further increasing its capacity to 250,000 bpd and significantly expanding its ability to process heavy sour crude oil. Since the acquisition of the Lima refinery in 1998, we have improved the product distribution logistics surrounding the refinery to allow the refinery to increase its throughput and more fully utilize that facility s 170,000 bpd capacity. We allocate capital to these projects based on a rigorous analysis of the expected return on capital. Based upon such a review of our 80,000 bpd Blue Island, Illinois refinery, we determined that, due to its poor competitive position as a relatively small refinery configured to process primarily light sweet crude oil, it would not have been able to meet our return on capital and free cash flow targets. As a result, we closed the Blue Island refinery in January 2001. In September 2002, we ceased refining operations at our Hartford refinery for the same reasons. The Hartford refinery would not have been able to meet our return on capital and free cash flow targets due to its relatively small size and the amount of investment necessary to meet new federally mandated fuel specifications. These productivity improvements, together with the acquisitions of our Port Arthur and Lima refineries, and the closure of non-competitive capacity strengthened our asset base, increased our coking capacity from 18,000 bpd to 113,000 bpd, increased our cracking capacity from 70,000 bpd to 178,000 bpd and increased our capacity to process sour and heavy sour crude oil from 45,000 bpd in 1994 to 200,000 bpd, an approximate 340% increase.

Improved our Operations and Safety Performance. We have implemented a number of programs which increased the reliability of our operations and improved our safety performance resulting in a reduction of our recordable injury rate from 3.12 to 1.14 per 200,000 hours worked. In 2001, we appointed a director of reliability, established an internal benchmarking and best practices program, developed a root-cause analysis program and installed an automated maintenance management system. Over the last several years, we made significant expenditures to improve our safety record. As a result, we have significantly reduced our company-wide recordable injuries and lost time injuries, each as defined by the Occupational Safety and Health Administration, or OSHA. We reduced our recordable injury rate by approximately 60% from 1995 to September 2002. From our acquisition of the Lima refinery in July 1998 through the end of 2001 the refinery accumulated over approximately three million employee hours without a lost time injury. From August 1997 through the third quarter of 2001, our Port Arthur refinery accumulated over seven million employee hours without a lost time injury. The streak ended on October 4, 2001 when our Port Arthur refinery incurred its first lost time injury in over four years. According to a survey by the National Petrochemical & Refiners Association, or NPRA, which was conducted for year-end 1999, of the approximately 218 United States refining and chemical facilities included in the survey, only five such facilities had ever achieved the five million employee hour milestone.

Expanded our Unbranded Petroleum Product Distribution Capabilities. We expanded and enhanced our capabilities to supply fuels on an unbranded basis to include the Midwest, Gulf Coast, southeastern and eastern United States. As part of the sale of our terminal operations, we gained access, subject to availability, to an extensive pipeline and terminal network for the distribution of products from each of our refineries.

Reduced Operating Costs. We reduced our operating costs as evidenced by a reduction of our refining employees per thousand barrels from 7.2 to 3.4.

In February 2002, we recruited a new chairman and chief executive officer, Thomas D. O Malley, the former chairman and chief executive officer of Tosco Corporation and former vice chairman and director of Phillips Petroleum Corporation. Mr. O Malley has over 25 years of industry experience and a proven track record of successfully operating, growing and enhancing shareholder value. Since then, we have improved our competitive position as a result of the following:

Recruited and Developed an Experienced Management Team. Mr. O Malley has assembled an executive management team, consisting of Henry M. Kuchta, president and chief operating officer, who joined us in

April 2002, William E. Hantke, executive vice president and chief financial officer, who joined us in February 2002, Joseph D. Watson, who joined us in March 2002 as senior vice president and chief administrative officer and currently serves as our senior vice president corporate development, and Michael D. Gayda as senior vice president, general counsel and secretary, who joined us in October 2002. These executive officers have an average of almost twenty years experience in the energy and refining industry. In addition, our operational management team has an average of 26 years of energy industry experience.

Completed our IPO. On May 3, 2002, we completed an initial public offering of 20.7 million shares of common stock. The initial public offering, plus the concurrent purchases of 850,000 shares in the aggregate by Thomas D. O Malley and two of our independent directors, netted proceeds to us of approximately $482 million. The proceeds from the offering were committed to retire certain indebtedness of our subsidiaries.

Completed our Sabine Restructuring. On June 6, 2002, we completed a series of transactions, referred to herein as the Sabine restructuring, that resulted in, among other things, all the senior secured debt of Sabine and its subsidiaries, other than the 12 $^1/2$% senior secured notes, being paid in full, all commitments under the working capital facility and certain insurance policies being terminated and Sabine and its subsidiaries becoming wholly owned subsidiaries of PRG. In connection with the Sabine restructuring, PRG fully and unconditionally guaranteed, on a senior unsecured basis, the payment obligations under the notes. The Sabine restructuring was permitted by the successful consent solicitation of holders of the notes.

Closed our Hartford, Illinois Refinery. In late September 2002, we ceased refining operations at our Hartford refinery after concluding there was no economically viable method of reconfiguring the refinery to produce fuels meeting new gasoline and diesel fuel specifications mandated by the federal government. Despite ceasing operations, we continue to pursue all strategic options to mitigate the loss of jobs and refinery capacity in the Midwest.

Pending Acquisition of the Memphis Refinery. We entered into an agreement in November 2002 with The Williams Companies, Inc. and certain of its subsidiaries to purchase their Memphis, Tennessee refinery and related supply and distribution assets.

Actions to Reduce Operating and General and Administrative Costs. We have taken and, are continuing to take, steps to reduce our operating and general and administrative costs, including:

- reducing our St. Louis-based administrative workforce by 107 positions, or approximately one-third of the total St. Louis administrative workforce in April 2002;
- announcing our intention to eliminate additional administrative positions by the end of the first quarter of 2003;
- eliminating approximately 80 of our non-represented refinery positions in October 2002; and
- entering into a new crude oil supply agreement for our Lima refinery in October 2002 that we believe will reduce our crude acquisition costs for Lima by roughly 20 cents per barrel.

Market Trends

We believe that the outlook for the United States refining industry is attractive due to the following trends:

Favorable Supply and Demand Fundamentals. We believe that the supply and demand fundamentals for refined petroleum products have improved since the late 1990s and will continue to improve. Decreasing petroleum product demand and deregulation of the domestic refining industry in the 1980s, along with new fuel standards introduced in the early 1990s, contributed to years of decreasing domestic refining capacity. According to the Department of Energy s Energy Information Administration, or EIA, and the Oil and Gas Journal s 2001 Worldwide Refinery Survey, the number of United States refineries has decreased from a peak of 324 in 1981 to

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143 in January 2002. The EIA projects that capacity additions at existing refineries will increase total domestic refining capacity at an annual rate of only 0.5% per year over the next two decades and that utilization will remain high relative to historic levels, ranging from 91% to 95% of design capacity. We believe that impending regulatory requirements will result in the rationalization of non-competitive refineries, further reducing refining supply.

Net imports of petroleum products, largely from northwest Europe and Asia, have historically supplemented domestic refining supply shortfalls, accounting for a relatively consistent amount of approximately 7% of total United States supply over the last 15 years. We expect that imports will continue to occur primarily during periods when refined product prices in the United States are materially higher than in Europe and Asia.

While refining capacity growth is expected by the EIA to be nominal, the EIA expects demand for petroleum products to continue to grow steadily at 1.3% per year over the next two decades. Almost 96% of the projected growth is expected to come from the increased consumption of light products including gasoline, diesel, jet fuel and liquefied petroleum gas.

Increasing Supplies of Lower Cost Sour and Heavy Sour Crude Oil. We believe that increasing worldwide supplies of lower-cost sour and heavy sour crude oil will provide an increasing cost advantage to those refineries with complex configurations that are able to process these crude oils. Purvin & Gertz, an independent engineering firm, estimates that the total worldwide heavy sour crude oil production will increase by approximately 39% from 9.7 million bpd in 2000 to 13.5 million bpd in 2010, resulting in a continuation of the downward price pressure on these crude oils relative to benchmark West Texas Intermediate crude oil. Over the next several years, significant volumes of sour and heavy sour crude oils are expected to be imported into the United States, primarily from Latin America and Canada. Purvin & Gertz expects domestic imports of this production to increase from 3.0 million bpd presently to 5.3 million bpd by 2010.

Increasing Demand for Specialized Refined Petroleum Products. We expect that products meeting new and evolving fuel specifications will account for an increasing share of total fuel demand, which may benefit refiners possessing the capabilities to blend and process these fuels. As part of the Clean Air Act of 1990 and subsequent amendments, several major metropolitan areas in the United States with air pollution problems are required to use reformulated gasoline meeting certain environmental standards. According to the EIA, demand for reformulated gasoline and the oxygenates used in its production will increase from approximately 3.3 million bpd in 2000 to approximately 4 million bpd in 2010, accounting for approximately 40% of all annual gasoline sales. According to officials of the United States Department of Energy, the trend toward banning MTBE as a blendstock in reformulated gasoline will result in an annual reduction of the gasoline supply by 3% to 4%.

Continued Consolidation of the Refining Sector. We believe that the continuing consolidation in the refining industry may create attractive opportunities to acquire competitive refining capacity. During the period from 1990 to 2001, the percentage of refining capacity owned by major integrated oil companies decreased from 66% to 62%. Many integrated oil companies divested refining assets rather than making costly investments to meet increasingly strict product specifications. During this same period, the percentage of refining capacity owned by the top ten owners of refining assets increased from 57% to 69% and the share held by independent refiners increased from 16% to 33%. New environmental regulations will require the refining sector to make substantial investments in refining assets and pollution control technologies. We believe these substantial costs will likely force many smaller inefficient refiners out of the market.

Competitive Strengths

As a result of our transformation, we have developed the following strengths:

Refining Focus. We are a pure-play refiner, without the obligation to supply our own retail outlets or the cost of supporting our own retail brand. As a result, we are free to supply our products into the distribution channel or market that we believe will maximize profit. We do not own any other assets or businesses, such as petroleum exploration and production or retail distribution assets, that compete for capital or management attention. Therefore, our capital and attention are focused on improving our existing refineries and acquiring additional competitive refining capacity. Although many of our competitors are integrated oil companies that are better positioned to withstand market volatility, such competitors are not fully able to capitalize on periods of strong refining margins. See Competition.

Significant Refineries Located in Key Geographic Regions. Our Port Arthur and Lima refineries are logistically well located, modern facilities of significant size and scope with access to a wide variety of crude oils and product distribution systems. Our access to key port locations on the Gulf Coast enables us to ship waterborne crude oil to our Midwest refineries via major pipeline systems. Our Lima refinery provides us with a strong presence in the attractive PADD II market. This refinery also benefits from the facts that the Midwest region is dependent upon the import of supplies from outside the region and that the pipelines available to deliver products to the region are fully utilized, which effectively places a ceiling on external supply into the region, giving local refineries such as ours a logistical advantage. Therefore, any disruption in local refinery production or pipeline supply magnifies this supply shortage.

Significant Capacity to Process Low-Cost Heavy Sour Crude Oil. Our Port Arthur refinery, which possesses one of the largest coking units in the world, can process 80% heavy sour crude oil which gives us a cost advantage over other refiners that are not able to process high volumes of these less expensive crude oils.

Favorable Crude Oil Supply Contract with PEMEX Affiliate. We have a long-term heavy sour crude oil supply agreement with an affiliate of PEMEX that provides a stable and secure supply of Maya crude oil. This contract, which currently covers approximately one-third of our company-wide crude oil requirements, contains a mechanism intended to provide us with a minimum average coker gross margin and to moderate fluctuations in coker gross margins during an eight-year period beginning April 1, 2001. Essentially, if the formula-based coker gross margin set forth in the contract, which is calculated on a cumulative quarterly basis, results in a shortfall from the support amount of $15 per barrel, we receive discounts from the PEMEX affiliate. In the event that there is a recovery of a prior shortfall upon which we received a discount from the PEMEX affiliate, we would reimburse the PEMEX affiliate in the form of a crude oil premium. Since we are not required to pay premiums in excess of accumulated net shortfalls, we retain the benefit of net cumulative surpluses in our coker gross margins as compared to the support amount of $15 per barrel. For purpose of comparison, the $15 per barrel minimum average coker gross margin support amount equates to a WTI/Maya crude oil price differential of approximately $6 per barrel using market prices during the period from 1988 to September 2002, which slightly exceeds actual market differentials during that period. See Refinery Operations Gulf Coast Operations Port Arthur Refinery for a further discussion of this contract.

Experienced and Committed Growth-Oriented Management Team. Our chairman and chief executive officer, Thomas D. O Malley, has a proven track record in the refining industry. From 1990 to 2001 Mr. O Malley was chairman and chief executive officer of Tosco Corporation. During that period, Mr. O Malley led Tosco Corporation through a period of significant growth in operations and shareholder returns through acquisitions. At Premcor, Mr. O Malley has assembled an experienced and committed management team consisting of executives who have held management positions in growth-oriented organizations in the energy sector.

Business Strategies

Our goal is to be a premier independent refiner and supplier of unbranded petroleum products in the United States and to be an industry leader in growing shareholder value. We intend to accomplish this goal, grow our business, enhance earnings and improve our return on capital by executing the following strategies, which we believe capitalize on our existing competitive strengths.

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Grow Through Acquisitions and Discretionary Capital Expenditure Projects at Our Existing Refineries. We intend to pursue timely and cost-effective acquisitions of crude oil refining capacity and undertake discretionary capital expenditure projects to improve, upgrade, and potentially expand our Port Arthur and Lima refineries. We will pursue opportunities that we believe will be promptly accretive to earnings and improve our return on capital, assuming historic average margins and crude oil differentials.

We believe that the continuing consolidation in our industry, the strategic divestitures by major integrated oil companies and the rationalization of specific refinery assets by merging companies will present us with attractive acquisition opportunities. We are currently evaluating several refinery acquisitions, some of which may be significant. In addition, based upon our engineering and financial analysis, we have identified discretionary capital projects at our Port Arthur and Lima refineries that we believe should, if undertaken, be accretive to earnings and generate an attractive return on capital. For example, in conjunction with a project to comply with new diesel fuel specifications, we have initiated a project at our Port Arthur refinery to expand this refinery to 300,000 - 400,000 bpd. We are also currently evaluating potential projects to reconfigure our Lima refinery to process a more sour and heavier crude slate. The management team assembled by Mr. O Malley has a proven track record of growing businesses via acquisitions, which we believe complements an existing strength of our organization. Since 1995, we have demonstrated our expertise in evaluating, structuring, implementing and integrating projects, as well as our acquisition and technical abilities by transforming our asset base through the acquisition of, and subsequent performance enhancement at, our Port Arthur and Lima refineries. We believe we are well situated to capitalize on these acquisitions and discretionary capital project opportunities.

In executing the strategies outlined above, we want to own and operate refineries, whether they be our existing refineries or refineries we may acquire in the future, which not only prosper in good market conditions, but are resilient during downturns in the market. We believe this resiliency can be created by, among other things:

- being a low-cost operator of safe and reliable refineries with a continuous focus on controlling costs;
- having an inherent cost advantage due to lower feedstock costs, such as the cost advantage which comes from having significant sour and heavy sour crude oil processing capabilities;
- owning refineries in strategic geographic locations; and
- having the capability to produce and distribute a variety of the fuels required by varying regional fuel specifications.

Promote Operational Excellence in Safety and Reliability. We will continue to devote significant time and resources toward improving the safety and reliability of our operations. We will seek to increase operating performance through our commitment to our preventative maintenance program and to training and development programs such as our current proactive manufacturing and defect elimination programs. We will continue to emphasize safety in all aspects of our operations. We believe that a superior safety record is inherently tied to profitability and that safety can be measured and managed like all other aspects of our business. We have identified several projects designed to increase our operational excellence. For example, at our Port Arthur refinery we are pursuing a portfolio of projects designed to increase reliability. At Lima, we have identified and are implementing a number of projects designed to decrease energy consumption and improve safety.

Create an Organization Highly Motivated to Enhance Earnings and Improve Return on Capital. We intend to create an organization in which employees are highly motivated to enhance earnings and improve return on capital. In order to create this motivation, we have adopted a new annual incentive program under which the annual bonus award for every employee in the organization is dependent to a substantial degree upon earnings. The primary parameter for determining bonus awards under the program for our executive officers and our senior level management team members is earnings. The program allows our executive officers and other senior

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management team members to earn annual bonus awards only if certain predetermined earnings levels are met, but provides significant bonus opportunities if those levels are exceeded. For the remainder of our employees, earnings is a substantial factor which determines whether a bonus pool is available for annual rewards. In approving annual awards under the program, the compensation committee of our board of directors will also consider our return on capital, and our environmental, health and safety performance.

Refinery Operations

We currently own and operate two refineries: our Port Arthur, Texas refinery comprises our Gulf Coast operations; our Lima, Ohio refinery comprises our Midwest operations.

In late September 2002, we ceased operations at our Hartford, Illinois refinery. We concluded that there was no economically viable manner of reconfiguring the refinery to produce fuels which meet new gasoline and diesel fuel specifications mandated by the federal government. We are pursuing all strategic options, including expanding the uses of the petroleum product and distribution facility and selling or leasing the refinery, to mitigate the loss of jobs and refining capacity in the Midwest. For a discussion of the pretax charge to earnings that we recorded in 2002 as a result of the closure of our Hartford refinery, see Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Nine Months Ended September 30, 2002 Compared to Nine Months Ended September 30, 2001 Refinery Restructuring and Other Charges Hartford Refinery Closure.

Our aggregate crude oil throughput capacity at our two refineries is 420,000 bpd. The configuration at each of our refineries is single-train coking, which means that each of our refineries has a single crude unit and a coker unit. The following table provides a summary of key data for our refineries, excluding the now closed Hartford refinery, as of September 30, 2002 and for the nine months then ended.

Refinery Overview

	Port Arthur, Texas	Lima, Ohio	Combined
Crude distillation capacity (bpd)	250,000	170,000	420,000
Crude slate capability:			
Heavy sour	80%	%	48%
Medium and light sour	20	10	16
Sweet		90	36
Total	100%	100%	100%
Production			
Light products:			
Conventional gasoline	33.0%	53.6%	40.2%
Premium and reformulated gasoline	8.5	8.4	8.5
Diesel fuel	25.6	12.8	21.1
Jet fuel	11.0	16.2	12.8
Petrochemical feedstocks	7.2	5.5	6.6
Subtotal light products	85.3	96.5	89.2
Petroleum coke and sulfur	11.8	2.0	8.4
Residual oil	2.9	1.5	2.4
Total production	100.0%	100.0%	100.0%

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Products

Our principal refined products are gasoline, on and off-road diesel fuel, jet fuel, liquefied petroleum gas, petroleum coke and residual oil. Gasoline, on-road (low-sulfur) diesel fuel and jet fuel are primarily transportation fuels. Off-road (high-sulfur) diesel fuel is used mainly in agriculture and as railroad fuel. Liquefied petroleum gas is used mostly for home heating and as chemical and refining feedstocks. Petroleum coke, a by-product of the coking process, can be burned for power generation or used to process metals. Residual oil (slurry oil and vacuum tower bottoms) is used mainly as heavy industrial fuel, such as for power generation, or to manufacture roofing materials or create asphalt for highway paving. We also produce many unfinished petrochemical feedstocks that are sold to neighboring chemical plants at our Port Arthur and Lima refineries.

Gulf Coast Operations

The Gulf Coast, or PADD III, region of the United States, which is the largest PADD in the United States in terms of crude oil throughput capacity, is comprised of Alabama, Arkansas, Louisiana, Mississippi, New Mexico and Texas. According to the NPRA, 56 refineries were operating in PADD III as of December 31, 2001, with a total crude oil throughput capacity of approximately 7.5 million bpd.

The market has historically had an excess supply of products, with the EIA estimating light product demand, as of December 31, 2001, at approximately 2.2 million bpd and light product production at approximately 6.0 million bpd. Approximately 62%, or 3.7 million barrels, is exported mainly to the eastern seaboard or midwest markets.

Explorer, TEPPCO, Seaway and Phillips pipelines transport Gulf Coast product to markets located in the Midwest region, and the Colonial and Plantation pipelines transport products to markets located in the northeast and southeast United States. In addition to the product pipeline system, product can be shipped by barge and tanker to both the eastern seaboard and west coast markets.

Port Arthur Refinery

Our Port Arthur refinery is located on the Gulf Coast, which accounts for 47% of total domestic refining capacity and is one of the most competitive markets in the United States. We acquired the refinery from Chevron Products Company in February 1995. This refinery is located in Port Arthur, Texas approximately 90 miles east of Houston on a 4,000-acre site, of which less than 1,500 acres are occupied by refinery assets. Since acquiring the refinery, we have increased the crude oil throughput capacity from approximately 178,000 bpd to its current 250,000 bpd and expanded the refinery s ability to process heavy sour crude oil. The refinery now has the ability to process 100% sour crude oil, including up to 80% heavy sour crude oil. The refinery includes a crude unit, a catalytic reformer, a hydrocracker, a FCC unit, a delayed coker and a hydrofluoric acid alkylation unit. It produces conventional gasoline, reformulated gasoline, low-sulfur diesel fuel and jet fuel, petrochemical feedstocks, sulfur and fuel grade coke.

The heavy oil upgrade project at our Port Arthur refinery increased from 20% to 80% the refinery s capability of processing heavy sour crude oil. The project achieved mechanical completion in December 2000 and became fully operational in the first quarter of 2001. Both milestones were achieved on time and under budget. Final completion was achieved on December 28, 2001.

The project, which cost approximately $830 million, involved the construction of new coking, hydrocracking and sulfur removal capabilities and upgrades to existing units and infrastructure. According to Purvin & Gertz, the 80,000 bpd coker unit at the refinery is one of the largest in the world. The upgrades completed in 2000 included improvements to the crude unit, which increased crude oil throughput capacity from 232,000 bpd to 250,000 bpd. Our Port Arthur refinery is now particularly well suited to process significantly greater quantities of lower-cost heavy sour crude oil. The heavy oil upgrade project has significantly improved the financial performance of the refinery. Our subsidiary, PACC, which owns the coker, the hydrocracker, the sulfur removal unit and related assets and equipment and leases the crude unit and the hydrotreater from another of our subsidiaries, The Premcor Refining Group, sells the refined products and intermediate products produced by the heavy oil processing facility to The Premcor Refining Group pursuant to arm s length pricing formulas based on public market benchmark prices. The Premcor Refining Group then sells these products to third parties.

Feedstocks and Production at Port Arthur Refinery

	For the Year Ended December 31,						For the Nine Months Ended September 30, 2002	
	1999		2000		2001			
	bpd (thousands)	Percent of Total	bpd (thousands)	Percent of Total	bpd (thousands)	Percent of Total	bpd (thousands)	Percent of Total
Feedstocks								
Crude oil throughput:								
Sweet crude oil	10.4	5.0%	3.6	1.7%		%		%
Medium and light sour crude oil	156.2	75.8	155.1	74.9	48.3	20.0	39.5	16.8
Heavy sour crude oil	33.4	16.2	43.4	21.0	181.5	75.2	189.6	80.8
Total crude oil	200.0	97.0	202.1	97.6	229.8	95.2	229.1	97.6
Unfinished and blendstocks	6.0	3.0	5.0	2.4	11.4	4.8	5.7	2.4
Total feedstocks	206.0	100.0%	207.1	100.0%	241.2	100.0%	234.8	100.0%
Production								
Light products:								
Conventional gasoline	75.9	36.4%	73.4	34.9%	82.9	32.7%	83.5	33.0%
Premium and reformulated gasoline	15.6	7.5	18.1	8.6	24.4	9.6	21.6	8.5
Diesel fuel	61.1	29.3	58.0	27.5	77.2	30.4	64.7	25.6
Jet fuel	18.1	8.7	16.6	7.9	19.7	7.8	27.7	11.0
Petrochemical feedstocks	23.1	11.1	23.7	11.3	18.3	7.2	18.3	7.2
Total light products	193.8	93.0	189.8	90.2	222.5	87.7	215.8	85.3
Petroleum coke and sulfur	11.1	5.3	11.3	5.3	26.5	10.4	29.9	11.8
Residual oil	3.6	1.7	9.5	4.5	4.8	1.9	7.3	2.9
Total production	208.5	100.0%	210.6	100.0%	253.8	100.0%	253.0	100.0%

Our Port Arthur refinery has significantly reduced combined recordable injuries and lost time injuries as defined by OSHA. The refinery s recordable injury rate, which reflects the number of recordable incidents per 200,000 hours worked, has improved from 4.40 in 1995 to an average of 1.39 as of September 30, 2002, compared to a United States refining industry average recordable injury rate of 1.35 in 2001. From August 1997 through the third quarter of 2001, our Port Arthur refinery accumulated over seven million employee hours without a lost time injury. The streak ended on October 4, 2001 when the refinery incurred its first lost time injury in over four years.

Feedstock and Other Supply Arrangements. The refinery s Texas Gulf Coast location is close to the major heavy sour crude oil producers and permits access to many cost-effective domestic and international crude oil sources via waterborne delivery to the refinery dock or from two terminals, the Sun terminal and the Oiltanking Beaumont Inc. terminal at Nederland, Texas, and through the Equilon pipeline. We purchase approximately 200,000 bpd of heavy sour crude oil, or 80% of the refinery s daily crude oil processing capacity, via waterborne delivery from an affiliate of PEMEX under term crude oil supply agreements, one of which is a long-term agreement with PACC expiring in 2011. Under this long-term agreement, PEMEX guarantees its affiliate s obligations to us. The remaining 20% of processing capacity utilizes a medium sour crude oil, the sourcing of which is optimally allocated between foreign waterborne crude oil and domestic offshore Gulf Coast sour crude oil delivered by pipeline.

Waterborne crude oil is delivered to the refinery docks or via the Sun terminal or the Oiltanking Beaumont terminal, both of which are connected by pipeline to our Lucas tank farm for redelivery to the refinery. Pipeline crude oil can also be received from Equilon s pipeline originating in Clovelly, Louisiana.

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The long-term crude oil supply agreement with the PEMEX affiliate provides our subsidiary, PACC, with a stable and secure supply of Maya crude oil. The long-term crude oil supply agreement includes a price adjustment mechanism designed to minimize the effect of adverse refining margin cycles and to moderate the fluctuations of the coker gross margin, a benchmark measure of the value of coker production over the cost of coker feedstock. This price adjustment mechanism contains a formula that represents an approximation of the coker gross margin and provides for a minimum average coker gross margin of $15 per barrel over the first eight years of the agreement, which began on April 1, 2001. The agreement expires in 2011.

On a monthly basis, the coker gross margin, as defined in the agreement, is calculated and compared to the minimum. Coker gross margins exceeding the minimum are considered a surplus while coker gross margins that fall short of the minimum are considered a shortfall. On a quarterly basis, the surplus and shortfall determinations since the beginning of the contract are aggregated. Pricing adjustments to the crude oil we purchase are only made when there exists a cumulative shortfall. When this quarterly aggregation first reveals that a cumulative shortfall exists, we receive a discount on our crude oil purchases in the next quarter in the amount of the cumulative shortfall. If, thereafter, the cumulative shortfall incrementally increases, we receive additional discounts on our crude oil purchases in the succeeding quarter equal to the incremental increase, and conversely, if, thereafter, the cumulative shortfall incrementally decreases, we repay discounts previously received, or a premium, on our crude oil purchases in the succeeding quarter equal to the incremental decrease. Cash crude oil discounts received by us in any one quarter are limited to $30 million, while our repayment of previous crude oil discounts, or premiums, are limited to $20 million in any one quarter. Any amounts subject to the quarterly payment limitations are carried forward and applied in subsequent quarters.

As of September 30, 2002, a cumulative quarterly surplus of $61.7 million existed under the contract. As a result, to the extent we experience quarterly shortfalls in coker gross margins going forward, the price we pay for Maya crude oil in succeeding quarters will not be discounted until this cumulative surplus is offset by future shortfalls. Assuming the WTI less Maya crude oil differential continues at its third quarter 2002 average of $4.92 per barrel, and assuming a Gulf Coast 3/2/1 crack spread similar to the third quarter 2002 average of $2.64 per barrel, we estimate the current $61.7 million cumulative surplus would be fully reversed after the third quarter of 2003. At that time, assuming a continuation of weak market conditions, we would be eligible to receive discounts on our crude oil purchases under the PEMEX contract as described above.

In May 2001, we entered into marine charter agreements with The Sanko Steamship Co., Ltd. of Tokyo, Japan, for three tankers custom designed for delivery to our docks. We intend to use the ships solely to transport Maya crude oil from the loading port in Mexico to our refinery dock in Port Arthur. Because of the custom design of the tankers, our dock will be accessible 24 hours a day by the tankers, unlike the daylight-only transit requirement applicable to ships approaching all other terminals in the Port Arthur area. In addition, the size of the custom-designed tankers will allow our crude oil requirements to be satisfied with fewer trips to the docks. We believe our marine charter arrangement will improve delivery reliability of crude oil to the Port Arthur refinery and will save approximately $10 million per year due to reduced third party terminal costs and the benefit of fewer trips. As of late 2002, all three ships had been delivered to us. The charter agreements have an eight-year term from the date of delivery of each ship and are renewable for two one-year periods.

Hydrogen is supplied to the refinery under a 20-year contract with Air Products and Chemicals Inc., or Air Products. Air Products has constructed, on property leased from us, a new steam methane reformer and two hydrogen purification units. Air Products also supplies steam and electricity to our Port Arthur refinery. If our requirements exceed the daily amount provided for under the contract, we may purchase additional hydrogen from Air Products. Certain bonuses and penalties are applicable for various performance targets under the contract.

Mixed butylenes from the FCC unit and the coker unit are processed for a fee by Huntsman Petrochemical Corporation, or Huntsman, to produce MTBE for sale or refinery consumption. The unused portion of the mixed butylene stream and incremental purchases are returned to our refinery for use as alkylation feedstock. Methanol required to produce the MTBE is purchased by us and delivered to Huntsman. The butylenes are transported to and from Huntsman by dedicated pipelines owned by Huntsman. This is a one-year renewable agreement between Huntsman and us, which may be cancelled upon 90 days notice.

We purchase Huntsman s entire production of pyrolysis gasoline, or pygas, produced from their Port Arthur ethylene cracker. Pygas is transported by dedicated pipeline from Huntsman to the refinery for use as a refinery gasoline blendstock. This agreement is for five years ending December 31, 2004, but can be cancelled by us, if desired as a result of gasoline specification changes due to Tier 2 gasoline standards, since the sulfur content of pygas may exceed that which is permitted by the regulations.

Energy. We generate most of the electricity for our Port Arthur refinery in our own cogeneration plants. The remainder of our electricity needs is supplied under a long-term agreement with Air Products, which has a cogeneration plant as part of its on-site hydrogen plant. In addition, we buy power from Entergy Gulf States, Inc., or Entergy, under peak load conditions, or if a generator experiences a mechanical failure. During times when we have excess power, we sell the excess to Entergy. Entergy has exercised its right to terminate the agreement because of impending deregulation, which deregulation is expected to occur in mid-2003. The agreement will stay in effect on a month-to-month basis until deregulation occurs. We are in the process of making alternative arrangements to replace the Entergy agreement.

Our Port Arthur refinery purchases natural gas at a price based on a monthly index, pursuant to a contract with Entex Gas Marketing, a subsidiary of Reliant Energy, that terminates in June 2003. The contract provides for 60,000 million btu of natural gas per day on a firm, uninterruptible basis, which is the amount of natural gas consumed by us each day at the refinery. The contract also allows for wide flexibility in volumes at a specified pricing formula. If we need to replace this contract, there are many alternative sources of natural gas available.

Product Offtake. The gasoline, low-sulfur diesel and jet fuel produced at our Port Arthur refinery are distributed into the Colonial pipeline, Explorer pipeline, TEPPCO pipeline or through the refinery dock into ships or barges. The advantage of a variety of distribution channels is that it gives us the flexibility to direct our product into the most profitable market. The TEPPCO pipeline is fed directly out of the refinery tankage, through pipelines we own and operate. The Colonial and Explorer pipelines are fed from our Port Arthur Products Station tank farm, which we partly own through a joint venture with Motiva Enterprises LLC and Unocal Pipeline Company, operated by Equilon Enterprises LLC, or Equilon. We also own the pipelines which distribute products from the refinery to the Port Arthur Products Station tank farm. Products loaded at the refinery docks come directly out of our Port Arthur refinery tankage. A pipeline also runs from our refinery to Equilon s Beaumont light products terminal. We supply all the products to the Equilon terminal. The petroleum coke produced is moved through the refinery dock by third-party shiploaders. The petroleum coke is sold to five customers under term agreements, for periods of one to four years.

Other Arrangements. Within our Port Arthur refinery, Chevron Phillips Chemical Company, L.P. operates a 164-acre petrochemical facility to manufacture olefins, benzene, cumene and cyclohexane. This facility is well integrated with the refinery and relies heavily on the refinery infrastructure for utility, operating and support services. We provide these services at cost. In addition to services, Chevron Phillips Chemical Company L.P. purchases feedstock from the refinery for use in its olefin cracker, aromatic extraction unit and propylene fractionator. By-products from the petrochemical facility are sold to the refinery for use as gasoline and diesel blendstock, saturate gas plant feedstock, hydrogen and fuel gas. Chevron Phillips Chemical Company L.P. has expressed intent to discontinue operation of the aromatic extraction unit. We are currently evaluating the impact of this discontinued operation on our refinery operations.

Chevron Products Company also operates a distribution facility on 102 acres within our Port Arthur refinery. The distribution center is operated by Chevron Products Company to blend, package, and distribute lubricants and grease. This facility also relies heavily on the refinery infrastructure for utility, operating and support services.

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Other Gulf Coast Assets

We own other assets associated with our Port Arthur refinery, including:

- a crude oil terminal and a liquefied petroleum gas terminal, with a combined capacity of approximately 5.0 million barrels;
- an interest in a jointly held product terminal operated by Equilon Pipeline Company;
- proprietary refined product pipelines that connect our Port Arthur refinery to our liquefied petroleum gas terminal;
- refined product common carrier pipelines that connect our Port Arthur refinery to several other terminals; and
- crude oil common carrier pipelines that connect our Port Arthur refinery to several other terminals and third party pipeline systems.

Midwest Operations

The Midwest, or PADD II, region of the United States, which is the second largest PADD in the United States in terms of crude oil throughput capacity, is comprised of North Dakota, South Dakota, Minnesota, Iowa, Nebraska, Kansas, Missouri, Oklahoma, Wisconsin, Illinois, Michigan, Indiana, Ohio, Kentucky and Tennessee. According to the NPRA, 27 refineries were operating in PADD II as of December 31, 2001, with a total crude oil throughput capacity of approximately 3.5 million bpd.

Production of light, or premium, petroleum product by refiners located in PADD II has historically been less than the demand for such product within that region, resulting in product being supplied from surrounding regions.

According to the EIA, total light product demand in PADD II, as of December 31, 2001, is approximately 3.9 million bpd, with refinery production of light products in PADD II estimated at approximately 2.9 million bpd. Net imports have supplemented PADD II refining in satisfying product demand and are currently estimated by the EIA at approximately 840,000 bpd, with the Gulf Coast continuing to be the largest area for sourcing product, accounting for approximately 670,000 bpd.

The Explorer, TEPPCO, Seaway, Orion, Colonial and Plantation pipelines are the primary pipeline systems for transporting Gulf Coast refinery output to PADD II. In addition, product began shipping via the Centennial product pipeline in April. Supply is also available via barge transport up the Mississippi River with significant deliveries into markets along the Ohio River. Although inefficient compared to pipelines, barge transport serves a role in supplying inland markets that are remote from pipeline access and in supplementing pipeline supply when they are bottlenecked or short of product.

Lima Refinery

Our Lima refinery, which we acquired from BP in August 1998, is located on a 650-acre site in Lima, Ohio, about halfway between Toledo and Dayton. The refinery, with a crude oil throughput capacity of approximately 170,000 bpd, processes primarily light, sweet crude oil, although 22,500 bpd of coking capability allows the refinery to upgrade lower-valued products. Our Lima refinery is highly automated and modern and includes a crude unit, a hydrocracker unit, a reformer unit, an isomerization unit, a FCC unit, a coker unit, a trolumen unit, an aromatic extraction unit and a sulfur recovery unit. We also own a 1.1 million-barrel crude oil terminal associated with our Lima refinery. The refinery can produce conventional gasoline, reformulated gasoline, jet fuel, high-sulfur diesel fuel, anode petroleum coke, benzene and toluene.

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Feedstocks and Production at Lima Refinery

	For the Year Ended December 31,						For the Nine Months Ended September 30, 2002	
	1999		2000		2001			
	bpd (thousands)	Percent of Total	bpd (thousands)	Percent of Total	bpd (thousands)	Percent of Total	bpd (thousands)	Percent of Total
Feedstocks								
Crude oil throughput:								
Sweet crude oil	120.7	103.6%	130.5	99.5%	136.5	99.7%	137.7	102.0%
Light sour crude oil			5.9	4.5	4.0	2.9	3.3	2.4
Total crude oil	120.7	103.6	136.4	104.0	140.5	102.6	141.0	104.4
Unfinished and blendstocks	(4.2)	(3.6)	(5.3)	(4.0)	(3.6)	(2.6)	(6.0)	(4.4)
Total feedstocks	116.5	100.0%	131.1	100.0%	136.9	100.0%	135.0	100.0%